CALIFORNIA
ENERGY
COMMISSION

NATURAL GAS MARKET ASSESSMENT

PRELIMINARY RESULTS

In Support of the
2007 Integrated Energy Policy Report

STAFF DRAFT REPORT

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EXECUTIVE SUMMARY

Introduction

California Energy Commission staff used the North American Regional Gas model to forecast natural gas prices for the *2007 Natural Gas Assessment*; but in a departure from previous years, the model results are presented as a “reference case” that recognizes that modeling results do not properly address the uncertainty of key variables. The reference case is therefore supplemented by a qualitative discussion of alternative assumptions and outcomes.

The results of staff’s preliminary analyses are presented in charts and tables, accompanied by text that summarizes key points. The report includes staff’s best estimate of natural gas demand, supply and price forecasts, and a discussion of natural gas infrastructure. The results of alternative scenarios are also presented.

A report on the development of worldwide liquefied natural gas (LNG) trade under different scenarios will be published separately. These analyses, including the LNG trade scenarios, will be presented at the June 7, 2007, Integrated Energy Policy Report Committee Workshop.

Major findings of the *2007 Natural Gas Assessment* report are presented below.

Demand

- North America’s gas demand is projected to increase at an annual rate of 2.1 percent over the next decade. The demand could expand from 70,655 million cubic feet (MMcf) per day in 2007 to 87,280 MMcf per day in 2017.

- The forecast growth rates of the United States, Canada, and Mexico could be 2.1 percent, 1.7 percent, and 3.6 percent, respectively.

- In the United States, the fastest growing sector for natural gas use is the power generation sector. The power generation sector could increase at an annual rate of 5.5 percent, while the total increase in other end-use sectors remains basically flat, increasing at a rate of only 0.5 percent annually. The predicted increase in natural gas consumption by the power generation sector is based on the need for CO_2 reduction, which could reduce the use of coal for electricity generation.

- While California’s natural gas demand is increasing at a much slower rate than either North America or the United States as a whole, California’s power generation demand could still grow by 1.1 percent between 2007 and 2017 while overall annual demand could grow by 0.8 percent for the same period. Some contributing factors to this slower growth in overall demand are:

- Increased use of renewable energy sources for electric power generation.
- Slower growth rates in electric generating capacity.
- The use of more efficient generating plants.
- Reduced natural gas demand for enhanced oil recovery.
- Flat growth in the industrial sector.

Supply

- North America's natural gas production is projected to decline during the forecast period, by about 0.5 percent on an annualized basis or 5 percent for the 10 year period.

- Natural gas from Arctic Canada and from Alaska's North Slope is assumed to be unavailable during the forecast period.

- U.S. natural gas production is also projected to decline during the forecast period, falling annually by about 0.5 percent or 5 percent overall.

- The forecast projects that North America's natural gas supplies would be augmented by LNG imports, increasing from 3,072 MMcf per day in 2007 to 24,404 MMcf per day in 2017.

- The amount of gas produced in the Southwest, which enters California at Blythe, gradually decreases during the forecast period as natural gas imported from Mexico (Costa Azul Facility) displaces domestic production from the Southwest.

- Importation of LNG is expected from Mexico into San Diego through the Transportadora De Gas Natural De Baja California (TGN) pipeline beginning in 2009. Gas imported from Costa Azul is projected to grow from zero to more than 1,500 MMcf per day by 2017.

- Each year from 2002 to 2007, the Energy Information Administration (EIA) has revised its natural gas production forecasts downwards.

- U.S. production has been relatively flat for the last several years even though natural gas prices and the number of natural gas wells drilled annually have both increased dramatically.

Infrastructure

- During the forecast period, the assessment results show that all major pipeline systems serving California operate at less than 100 percent capacity factors. For example, Kern River's capacity utilization hovers around 80 percent throughout the forecast horizon, while utilization of all other pipeline systems falls below 50 percent.

- Modeling results indicate that LNG entering California would displace natural gas from the Southwest.

- The assessment indicates that only two pipelines affecting California may need to expand. The pipelines, TGN southbound and North Baja westbound, now deliver conventional natural gas to their end users. However, after Costa Azul begins operations, both pipelines may reverse flow and expand to accommodate the flow of regasified LNG. TGN northbound flows gas into San Diego and North Baja eastbound flows gas into Blythe/Ehrenberg.

Price

- Price projections are in $2006 dollars unless otherwise noted.

- The model projects prices to fall early in the forecast period, and then rise to nearly $7 per MMBtu by 2017.

- Over the next 10 years, more available supply options could increase gas-on-gas competition.

- Basis spreads (difference between prices at two different locations) between Henry Hub (Louisiana) and other hubs increase during the forecast period. This implies that the Henry Hub price is not rising in lock step with other North American hubs and remains low because the majority of expected imported LNG coming into the Gulf Coast is close to Henry Hub.

- The basis spreads, that traditionally were negative, become positive. The discount that California has enjoyed relative to Henry Hub becomes a premium.

Alternative Cases

- Two approaches were used to acknowledge the uncertainty of predicting natural gas demand when developing low and high case demand assumptions—one quantitative and one qualitative.

- The quantitative approach uses the distribution of recorded demand growth to create a range around the expected demand case. This analysis demonstrates that a reasonable high case could be 1.5 to 2.0 trillion cubic feet (Tcf) higher than staff's Reference Case. A reasonable low case could be 1.5 to 2.0 Tcf lower than staff's case.

- The qualitative approach identifies specific factors that can each contribute to higher versus lower demand.

- A heuristic tool was developed to create a snapshot of natural gas supply that can be used to assess supply/demand balance.

- The high supply case assumes that production per well remains constant and that producers drill more wells. It demonstrates an imbalance (potentially met with LNG) of approximately 3 Tcf by 2017.

- The low supply case assumes that production per well declines and that the number of wells drilled is capped at the 2006 number of approximately 30,000 wells. It also assumes that Canadian supply falls off somewhat more quickly. In this case, the imbalance grows to nearly 10 Tcf by 2017.

- There is no consistent and clear-cut relationship between oil and natural gas prices.

CHAPTER 1: INTRODUCTION

Background

The outcome of staff's natural gas modeling, conducted for the *2005 Integrated Energy Policy Report* (*2005 IEPR*), was a single point forecast that incorporated the following expected trends in supply, demand, infrastructure, and price:

- Natural gas production from the "lower 48" states was expected to increase by 1.6 percent per year.

- Delivery of natural gas was expected from proposed LNG facilities on the east and west coasts.

- Steadily increasing demand growth was met largely through imports from other states and from Canada.

- Increasing natural gas prices reflected the ongoing combined effects of the energy crisis of 2001 and the devastating hurricanes of 2005.

- High prices from the above events were expected to be of a temporary nature.

- Short-term natural gas prices were expected to be volatile.

The equilibrium models used deterministically by the California Energy Commission (Energy Commission) and others cannot adequately capture all events—foreseen and unforeseen—that could ultimately affect California's natural gas situation. For example, the effect of both high or low temperature and variations in either rainfall or the annual snowpack could well increase the demand for additional natural gas- fired generation. Greenhouse gas (GHG) emission reduction policies could also affect whether either coal or natural gas is used to meet U.S. electricity demand. Future LNG supply could be affected by construction and expansion of LNG terminals, geopolitical issues, and supply diversions. Such uncertainties led to the *2005 IEPR* recommendation that staff further investigate alternative forecasting methods in the *2007 IEPR* cycle in order to better assess natural gas prices.

Approach for the 2007 Assessment

The approach for the *2007 Natural Gas Assessment* (*2007 Assessment*) is very different from that of previous assessments. Since 1989, Energy Commission staff has used the North American Regional Gas (NARG) model to forecast natural gas prices. Though staff continues to use NARG for the *2007 Assessment*, it is explicitly offered as a "reference case" in recognition that modeling results do not properly address the uncertainty of key variables. Staff did not have the opportunity to perform the appropriate stochastic analysis. Therefore, staff replaced the reference case with a qualitative discussion of alternative assumptions and outcomes that could reasonably occur around the reference case. Staff seeks feedback on the reference case, its results, and the range of alternative assumptions and outcomes stemming from its analyses.

This natural gas assessment report is one of several Energy Commission efforts relating to natural gas. Ongoing work by the California Energy Commission Public Interest Energy Research (PIER) program is evaluating the role and opportunities for natural gas storage. The results of this PIER work will be incorporated into future natural gas assessments prepared by staff.

Global developments limiting access to LNG supplies could affect the ability of LNG to meet the projected gap between natural gas supply and demand. For this reason, the Energy Commission requested that LNG expert James Jensen provides a report on the development of worldwide LNG trade under differing scenarios. His results are provided in the full LNG report that will be published separately.

Energy Commission staff is conducting a scenario analysis of alternative resource plans predicated upon large penetrations of preferred resources in order to gain insight into how selected performance measures—reliability, cost, and environmental impacts (such as GHG emissions and water use)—could change across resource cases. Different assumptions will result in a range of natural gas prices. Staff anticipates that a comparative review of scenario-derived prices and the natural gas prices discussed in this report will occur at a subsequent workshop in mid to late summer 2007.

Organization of this Report

The intent of this staff report is to provide information for the *2007 IEPR* on work products that are in various stages of development. The results of staff's preliminary analyses are presented in charts and tables, accompanied by text that summarizes key points. The report includes staff's assessments of natural gas demand, supply and price forecasts, and a discussion of natural gas infrastructure. Results of alternative cases are also presented and explained. Information contained in this assessment report, along with LNG trade scenarios, will be presented and discussed by staff at the Energy Commission's *Integrated Energy Policy Report* (IEPR) Committee Workshop on June 7, 2007.

CHAPTER 2: NATURAL GAS DEMAND

Major Findings

- North America gas demand is projected to increase at an annual rate of 2.1 percent over the next decade. The demand is expected to expand from 70,655 MMcf per day in 2007 to 87,280 MMcf per day in 2017.

- The anticipated growth rates of the United States, Canada, and Mexico could be 2.1 percent, 1.7 percent, and 3.6 percent, respectively.

- North America's gas demand is dominated by the United States at 83 percent, followed by Canada at 12 percent and Mexico at 5 percent.

- In North America, the United States' power generation gas demand is the fastest growing sector. The power generation sector is expected to increase at an annual rate of 5.5 percent. The total increase for other end-use sectors is essentially flat, increasing at an annual rate of 0.5 percent. The predicted increase in natural gas consumption by the power generation sector is based on CO_2 reduction.

- California's natural gas demand could increase at a much slower rate than either North America or the United States as a whole. California's power generation demand could grow by 1.1 percent between 2007 and 2017 while overall annual demand could grow by 0.8 percent for the same period. Some contributing factors to this slower growth in overall demand are:

  - Increased use of renewable energy sources for electric power generation.
  - Slower growth rate in electric generating capacity.
  - The use of more efficient generating plants.
  - Reduced gas demand for enhanced oil recovery.
  - Flat growth in the industrial sector.

Demand Sectors

To analyze the North American gas market, staff has divided consumption into several end-use sectors. These sectors are somewhat independent of one another in that the influence of various demand parameters differs across the sectors. The residential and commercial end-use sectors are both within the core sector since the consumer is not able to switch fuels.

The industrial sector, referred to as "non-core," has been divided into chemical and non-chemical sectors. Some of the end users in the industrial sector have the ability to switch fuels. Other major end use sectors that have been evaluated outside the industrial sector include gas demand associated with Alberta's oil sands and California's enhanced oil recovery (EOR).

The power generation sector has been considered a separate end-use sector since its demand for natural gas is dependent upon the demand for electricity.

The Energy Commission's Electricity Analysis Office forecasts the power generation mix for the western United States. This assessment of the power generation market for the West is used in determining the gas demand over the forecast period for the western power generation sector, see Appendix A: *Electric Generation and Transmission Infrastructure Development 2008 - 2017*.

The structure used to evaluate the gas market contains sectors that are inelastic and elastic to the change in natural gas price. Demand for natural gas in the inelastic sectors will not be responsive to changes in gas price. Conversely, the elastic demand sectors will respond to natural gas price changes. .

The inelastic demand sectors are:

- California gas demand in all sectors except enhanced oil recovery.
- Gas demand for power generation in the West.
- California enhanced oil recovery.
- Alberta oil sands.
- LNG exports (Alaska).

The elastic demand sectors are:

- Core
    - Residential (outside California)
    - Commercial (outside California)
- Industrial (outside California)
    - Chemical
    - Non-chemical
- Power generation (outside the West)

In developing the elasticity functions for various end use sectors, the following parameters had a significant influence on natural gas demand. Gas demand for the residential and commercial sectors was found to be a function of income, population, weather, and natural gas price. Industrial demand, in both the chemical and non-chemical sectors, was determined to be a function of industrial production, the price of natural gas, and the price of crude oil. These parameters are shown below:

Residential/Commercial

- Natural gas price
- Gross domestic product
- Heating degree days

- Population

Industrial Chemical/Industrial Non-Chemical
- Natural gas price
- Crude oil price
- Industrial production index

Demand Assumptions

The natural gas demand forecast requires the use of various forecasts for parameters that affect natural gas consumption. These forecasts include the economic outlook, population growth, and weather for the states, provinces, and regions in the United States, Canada, and Mexico.

Staff's outlook for the demand parameters determined to influence the natural gas market over the forecast period was based on historical trends and analysis by staff and on the use of forecasts published by both various government agencies and the gas industry. Staff also used the *2005 IEPR California Energy Demand Forecast*. Sources for this information are shown below, and the overall trend for gross domestic product and industrial production parameters is shown in Table 1.

- Gross domestic product
  - United States – U. S. Department of Commerce, Bureau of Economic Analysis
  - Canada – Canada National Statistical Agency

- Industrial Production Index
  - United States – U.S. Federal Reserve
  - Canada – Canada National Statistical Agency

- Oil price – U. S. Energy Information Administration (EIA), *Annual Energy Outlook* 2007 Reference Case

- Heating degree days – U. S. Department of Commerce, National Oceanic & Atmospheric Administration

- Population
  - United States – U. S. Census Bureau, Population Branch, Information & Research Services Internet Staff (Population Division)
  - California – State of California Department of Finance, *Population Projection by Race/Ethnicity for California and its Counties 2000–2050*
  - Canada – *Statistics Canada*, CANSIM Table 052-001, Projected Population for Canada, Provinces and Territories, July 1, 2000–2026

Table 1: Demand Assumptions

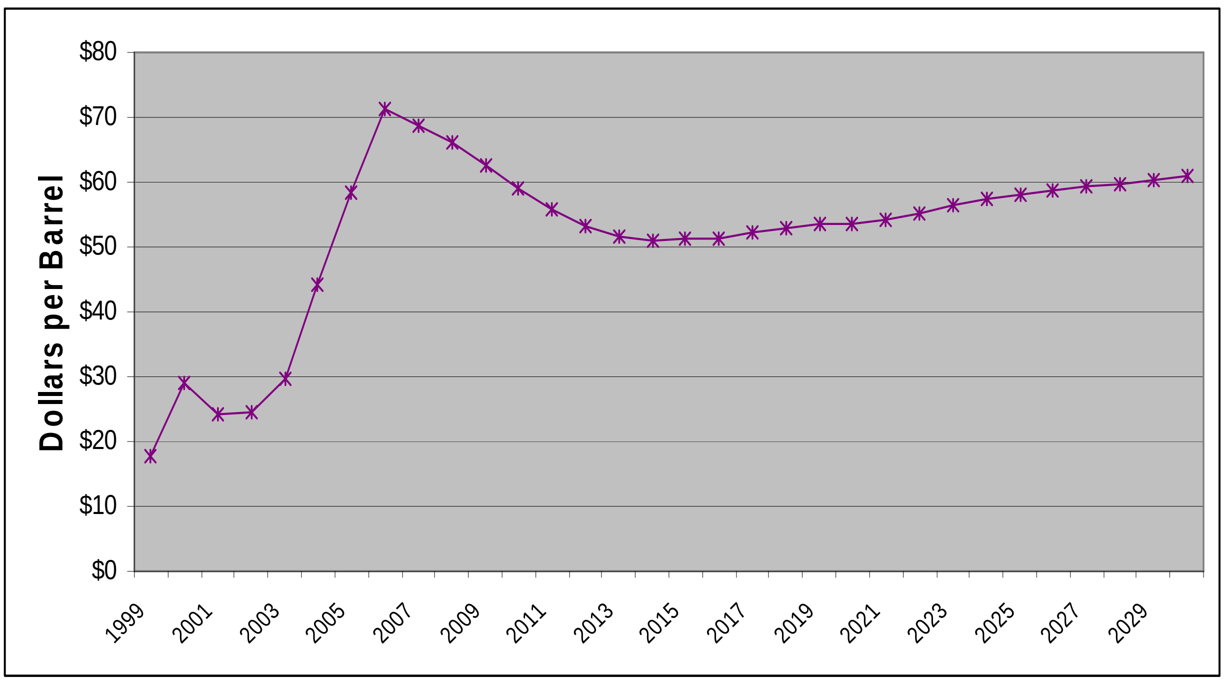
Demand Parameters	Annual Rate of Change 2007–2030
U.S. Gross Domestic Product	2.9 %
U.S. Industrial Production Index	2.2 %
Canada Gross Domestic Product	2.5 %
Canada Industrial Production Index	1.9 %

Source: Energy Commission Staff, 2007

Demand Results

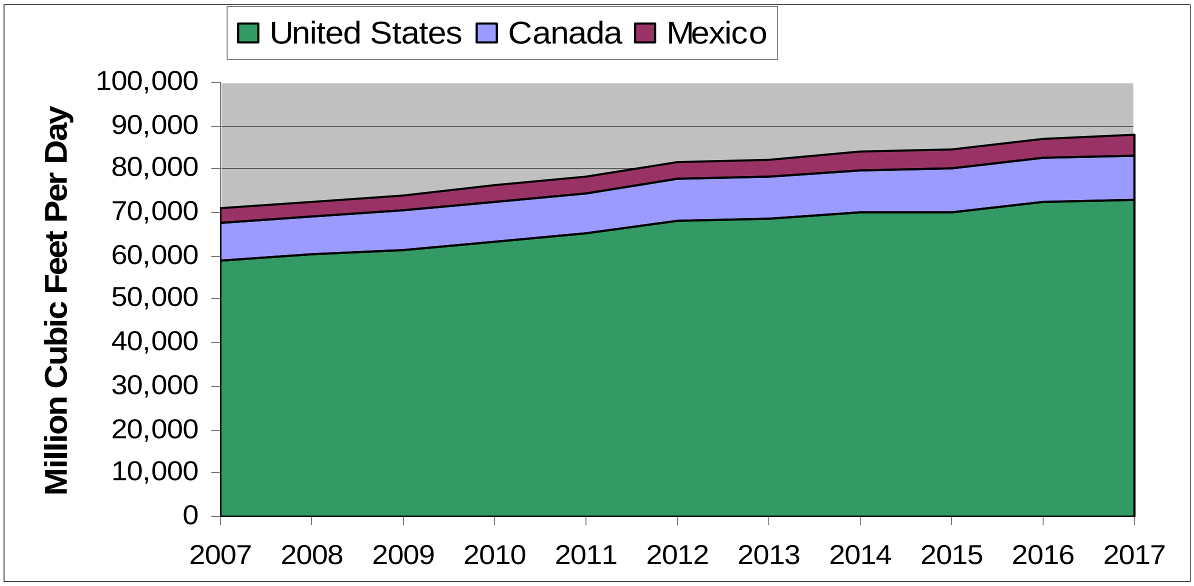
Figures 1 through 13 present model results for natural gas demand. Narrative directly below for some figures provides further explanation or elaboration of the results.

Figure 1: Annual Energy Outlook Crude Oil Forecast – Reference Case
$2006



Source: Energy Information Administration Annual Energy Forecast 2007 Reference Case

Figure 2: North America Natural Gas Demand*
(Million Cubic Feet per Day)

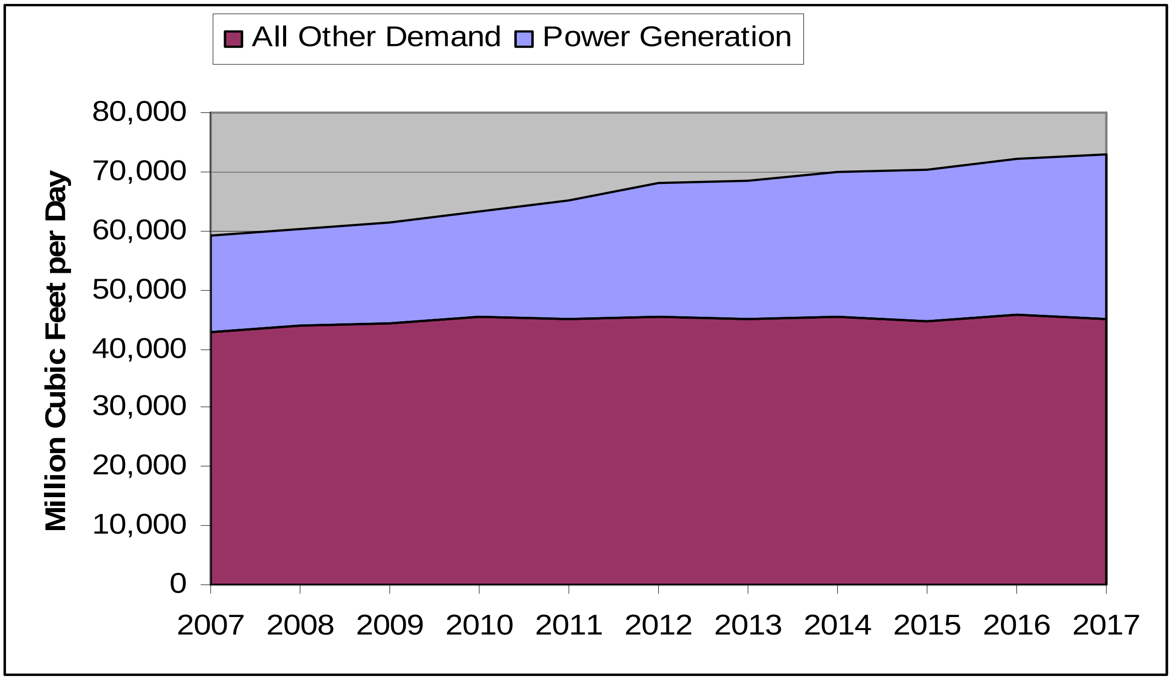


Source: Energy Commission Staff, 2007

*Forecast Demand:

Country	**2007**	**2017**	**Annual Change**
United States	59,172	72,900	2.1 %
Canada	8,630	10,226	1.7 %
Mexico	3,289	4,697	3.6 %
Total	*71,091*	*87,823*	*2.1 %*

Figure 3: United States Natural Gas Demand*
(Million Cubic Feet per Day)



Source: Energy Commission Staff, 2007

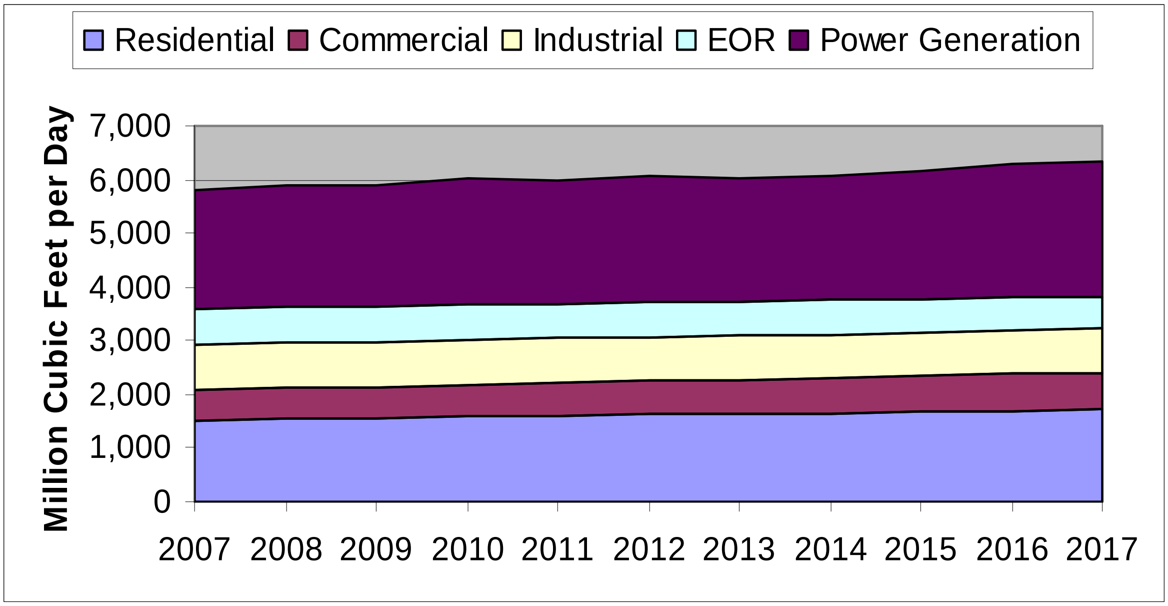
* Forecast Demand

End Use	2007	2017	Annual Change
Power Generation	16,210	27,910	5.5 %
All Other Uses	43,075	45,209	0.5 %
U.S. Total	59,285	73,119	2.1 %

The primary force driving the increase of natural gas demand in the United States is the power generation sector (Figure 3). Overall annual gas demand in the power generation sector is forecast to increase at 5.5 percent per year.

Gas demand associated with the power generation sector in the western United States is relatively flat in California, increasing at an annual rate of 1.1 percent. The forecast for western states, excluding California, has a projected gas demand increase for power generation of 4 percent annually. The greatest increase in gas demand by the power industry is expected to come from states east of the Rocky Mountains. The demand increase for this region is forecast to be 6.4 percent annually. The reference case has assumed that future electric generation will be tied to the reduction of CO_2 emissions. Since coal has the highest carbon content and natural gas the lowest, this results in natural-gas generating capacity having an advantage over coal-based generating capacity.

Figure 4: California Natural Gas Demand*
(Million Cubic Feet per Day)



Source: Energy Commission Staff, 2007

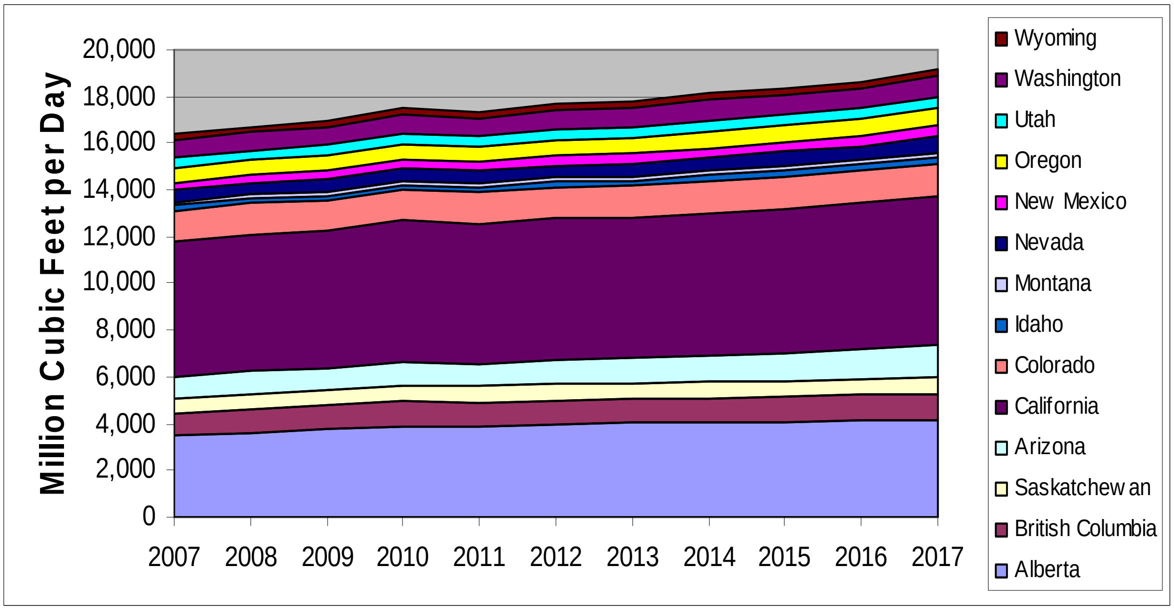
*Forecast Demand

End Use Sectors	2007	2017	Annual Change
Residential	1,510	1720	1.3 %
Commercial	575	685	1.8 %
Industrial	840	810	-0.4 %
Power Generation	2,220	2,485	1.1 %
Enhanced Oil Recovery	675	610	-1.0 %
Total	5,820	6,310	0.8 %

California's natural gas demand is forecast to increase at an annual rate of less than 1 percent (Figure 4). The residential and commercial sectors will see slight increases in gas demand of 1.3 percent for the residential sector and 1.8 percent for the commercial sector. The increase in gas demand for these sectors is related to continued growth in both the state's population and economy. The power generation sector is expected to experience continued growth, but at a slower rate over the next 10 years: 1.1 percent as compared with the last 10 years when growth increased by 3 percent annually.

Gas demand in the industrial sector is expected to be flat. It is believed that this projected flat demand is the result of the increase in gas prices over the last few years. As a result, industries with natural gas as a major component in their manufacturing processes had to either improve their energy efficiency or relocate to regions able to supply their gas at lower cost. Gas demand in California's Enhanced Oil Recovery (EOR) sector is also expected to decline. This decline stems from declining oil production and improvements in technology and efficiency.

Figure 5: Western United States and Canada Natural Gas Demand* (Million Cubic Feet per Day)



Source: Energy Commission Staff, 2007

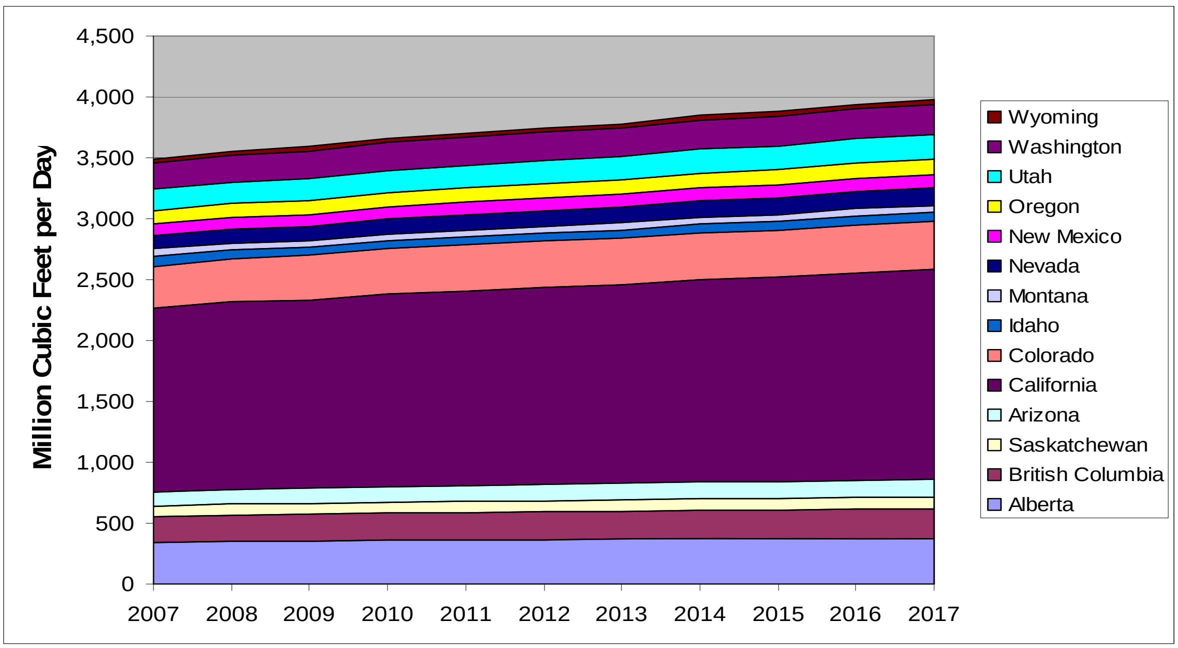
*Forecast Demand

State or Province	2007	2017	Annual Change
Canada			
Saskatchewan	430	470	0.8 %
British Columbia	970	1,065	0.9 %
Alberta	3,430	4,170	2.0 %
Total Western Canada	*4,830*	*5,705*	*1.7 %*
United States			
Wyoming	240	260	0.9 %
Washington	750	885	1.6 %
Utah	430	452	0.5 %
Oregon	635	750	1.7 %
New Mexico	290	485	5.4 %
Nevada	520	705	3.1 %
Montana	170	190	1.0 %
Idaho	195	230	1.7 %
Colorado	1,285	1,425	1.0 %
Arizona	960	1,440	4.1 %
California	5,820	6,315	0.8 %
Total Western U.S.	*11,295*	*13,135*	*1.5 %*
Total Western States and Provinces	*16,125*	*18,840*	*1.6 %*

Source: Energy Commission Staff, 2007

The increase in gas demand for the western United States and Canada is not as great as the expected increase in gas consumption throughout Canada and the United States as a whole (Figure 5). The main reason is the anticipated slow growth for gas consumption in California. California accounts for over 30 percent of the natural gas consumed in the West. Arizona, New Mexico, and Nevada are expected to have significant increases in gas consumption because of their population growth and power generation requirements, but these states together only account for less than 15 percent of gas consumed in the West.

Figure 6: Natural Gas Sector Residential Demand Western United States and Canada* (Million Cubic Feet per Day)



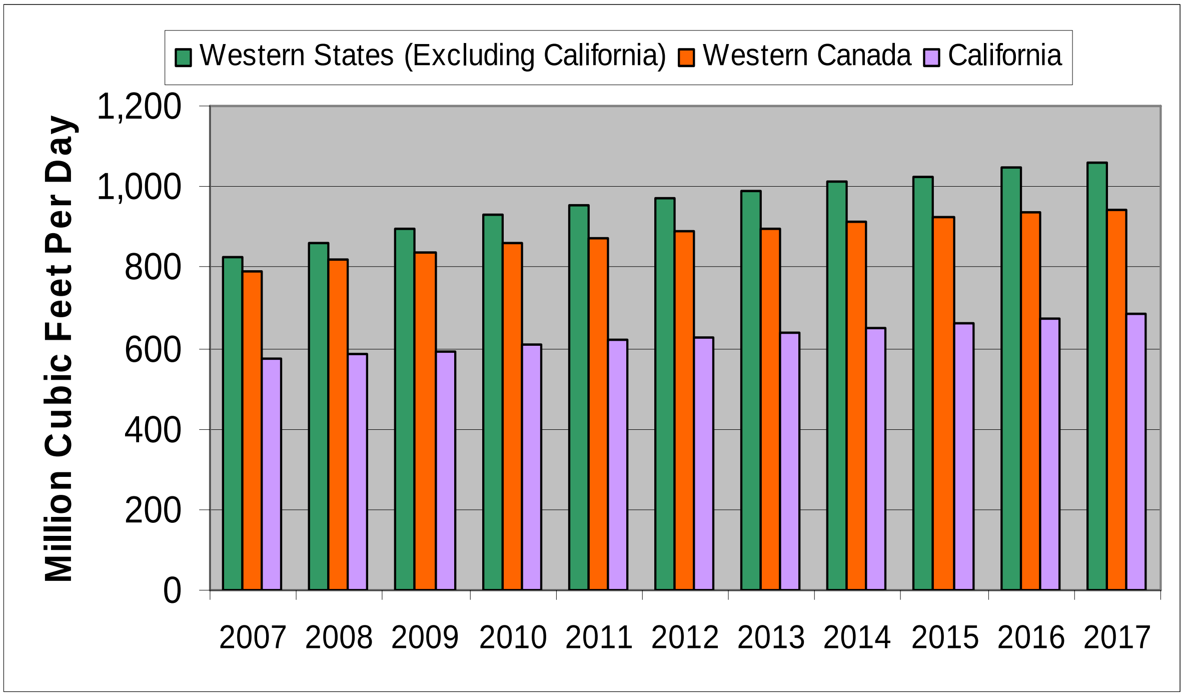
Source: Energy Commission Staff, 2007

* Forecast Demand

Residential Sector	2007	2017	Annual change
Western States Excluding California	1,343	1,545	1.5 %
Western Canada	641	708	1.0 %
California	1,508	1,722	1.3 %

Residential gas demand in the West is projected to increase from 3,492 MMcf per day to 3,975 MMcf per day by 2017 (Figure 6). The growth is fairly even across the West. Canada's residential gas demand forecast shows an annual increase of 1 percent annually, California's forecast has an increase of 1.3 percent, and the remaining states in the West are expected to experience residential demand increase of 1.5 percent annually. The increase in residential demand is comprised mostly of space and water heating, both of which are greatly influenced by population growth.

Figure 7: Natural Gas Sector Commercial Demand Western United States and Canada*
(Million Cubic Feet per Day)



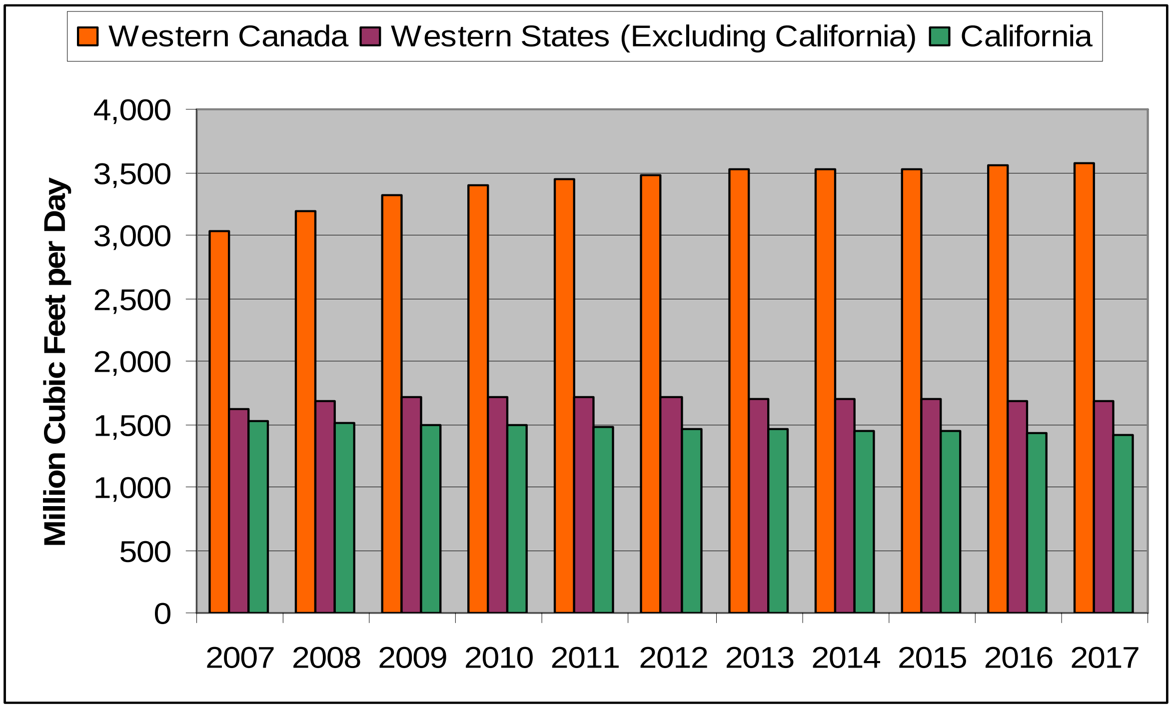
Source: Energy Commission Staff, 2007

* Forecast Demand

Commercial Sector	2007	2017	Annual change
Western States Excluding California	820	1,060	2.6 %
Western Canada	790	945	1.8 %
California	570	685	1.8 %

Gas demand in the commercial sector is expected to increase at an annual rate of 2 percent, growing from 2,180 MMcf per day to 2,690 MMcf per day by the end of the forecast period (Figure 7). The western states, excluding California, are forecast to have the fastest growth at 2.6 percent annually, followed by California and Western Canada at 1.8 percent. The major factors affecting commercial gas consumption are population growth and income. Over the forecast horizon, gross domestic product (GDP) is assumed to grow at a steady rate of 3 percent.

Figure 8: Natural Gas Sector Industrial Demand in the Western United States and Canada* (Million Cubic Feet per Day)



Source: Energy Commission Staff, 2007

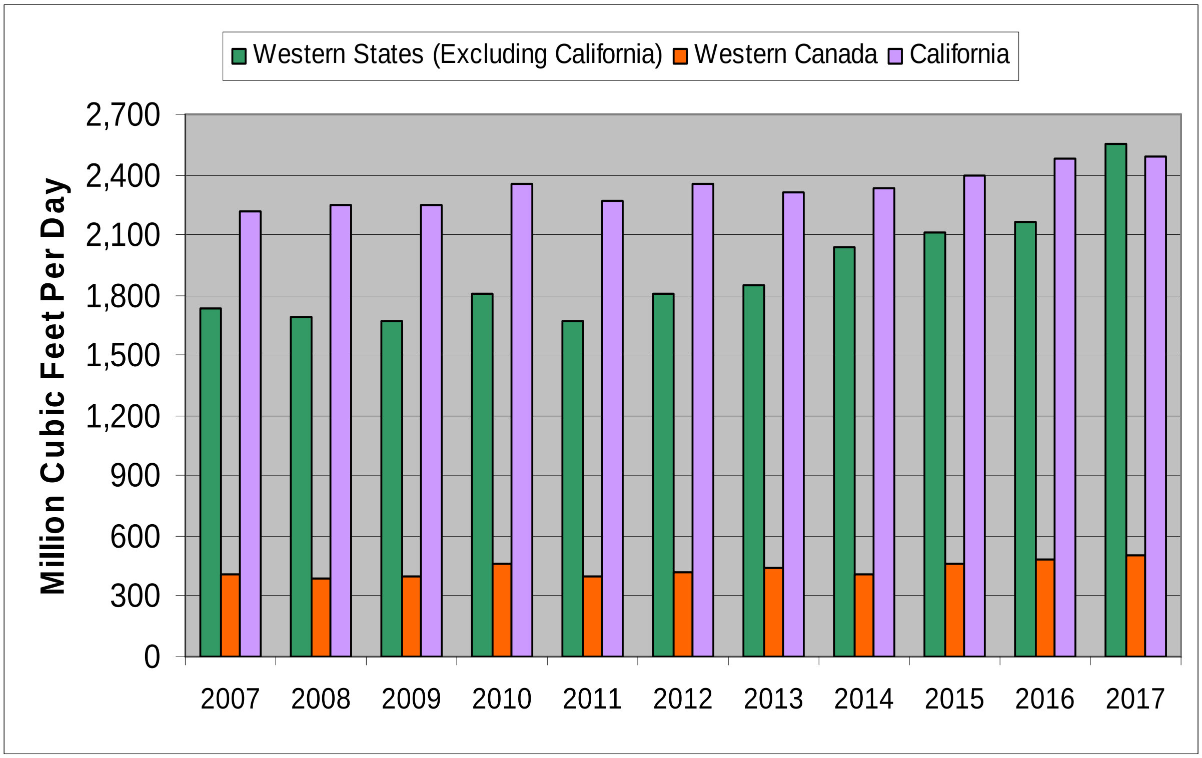
*Forecast Demand

Industrial Sector	2007	2017	Annual Change
Western Canada	3,030	3,567	1.7 %
Western States (Excluding California)	1,626	1,680	0.3 %
California	1,519	1,420	-0.8 %

The industrial gas demand for the western United States and Canada includes gas consumed in the industrial chemical and non-chemical sectors, the Alberta oil sands, and California's enhanced oil recovery (Figure 8). The total demand is forecast to increase from 6,175 MMcf per day in 2007 to 6,667 MMcf per day in 2017. Western Canada's industrial increase is driven by greater demand from the Alberta oil sands in anticipation of its increased production. The Alberta oil sands account for 29 percent of Western Canada's industrial demand. This is expected to increase to approximately 35 percent of the industrial demand by 2017. If gas demand for Alberta oil sands were not included in western Canada's industrial demand, the increase would be expected to be less than 1 percent annually.

The western states, excluding California, are expected to have flat industrial demand. California's industrial gas demand is expected to decrease because of declining enhanced oil production and essentially no growth in the chemical and non-chemical sectors.

Figure 9: Natural Gas Sector Power Generation Demand: Western United States and Canada* (Million Cubic Feet per Day)

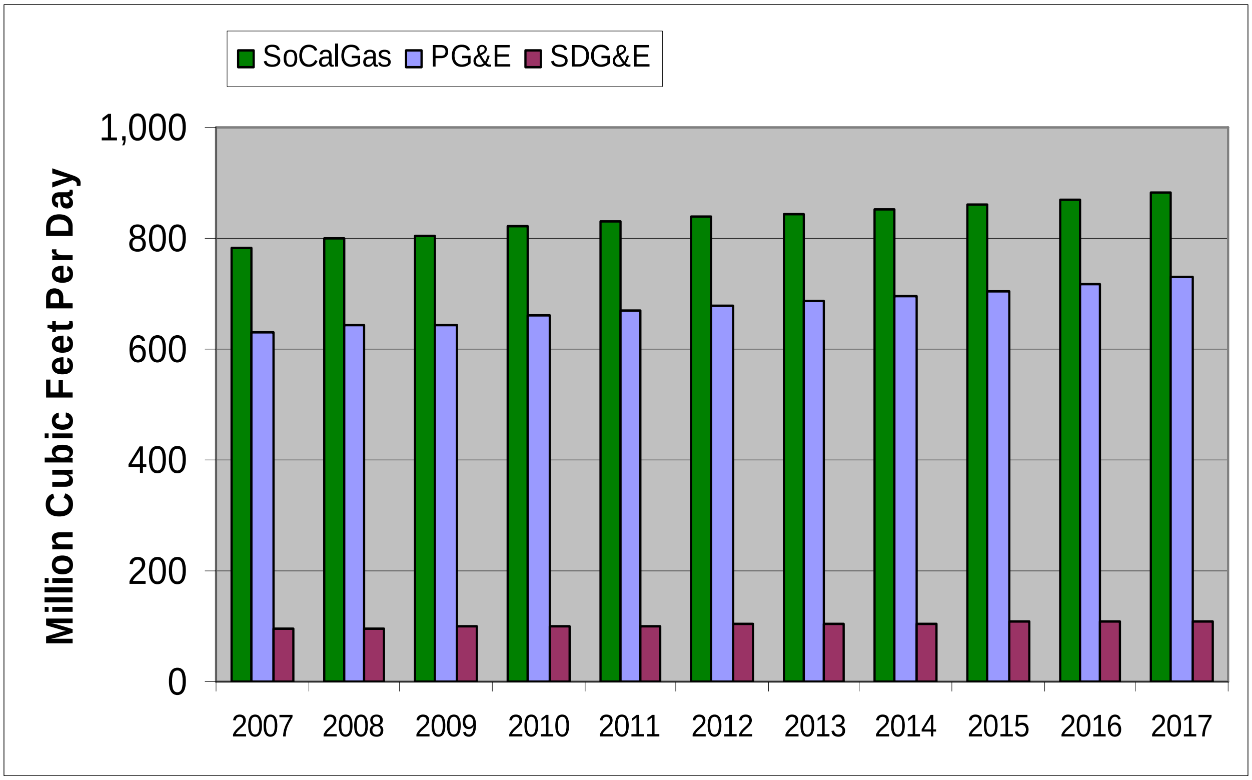


Source: Energy Commission Staff, 2007

*Forecast Demand

Power Generation Sector	**2007**	**2017**	**Annual Change**
Western States Excluding California	1,730	2,560	4.0 %
Western Canada	405	500	2.1 %
California	2,220	2,485	1.1 %

Figure 10: California Utilities Service Territories Natural Gas Demand – Residential* (Million Cubic Feet per Day)

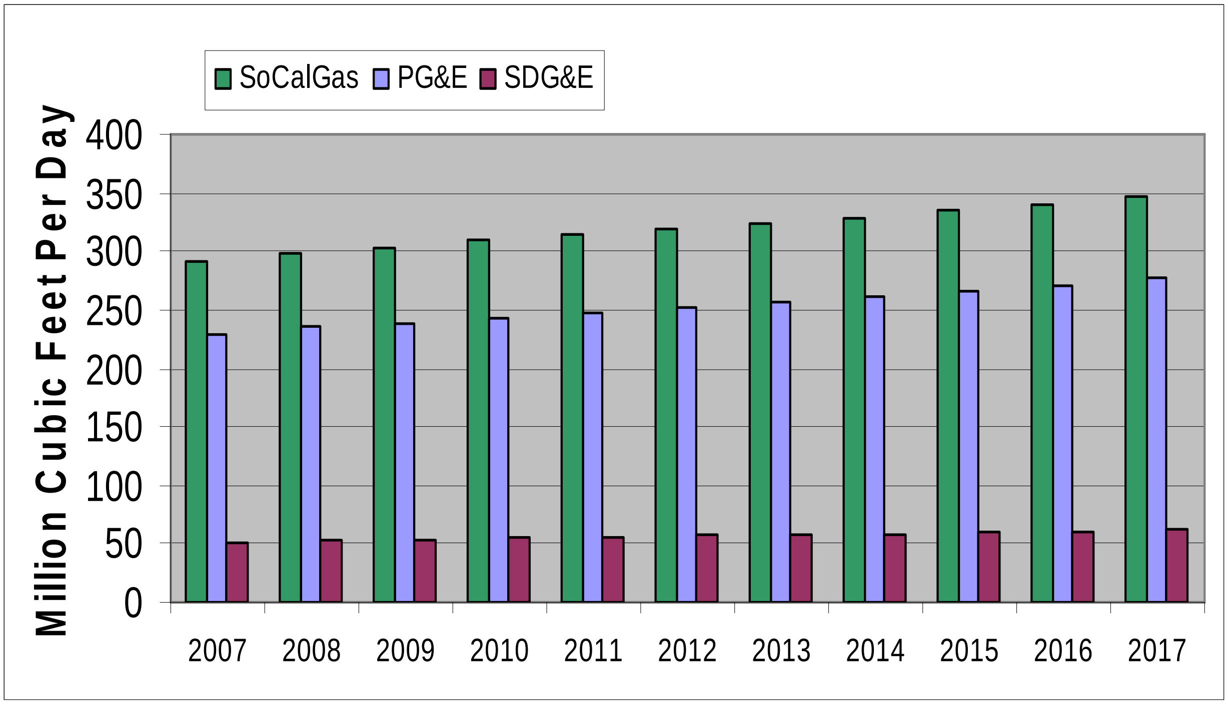


Source: Energy Commission Staff, 2007

*Forecast Demand

Residential Sector	2007	2017	Annual change
SoCalGas	784	881	1.2 %
PG&E	628	730	1.5 %
SDG&E	95	110	1.4 %

Figure 11: California Utilities' Service Territories: Natural Gas Demand – Commercial* (Million Cubic Feet per Day)

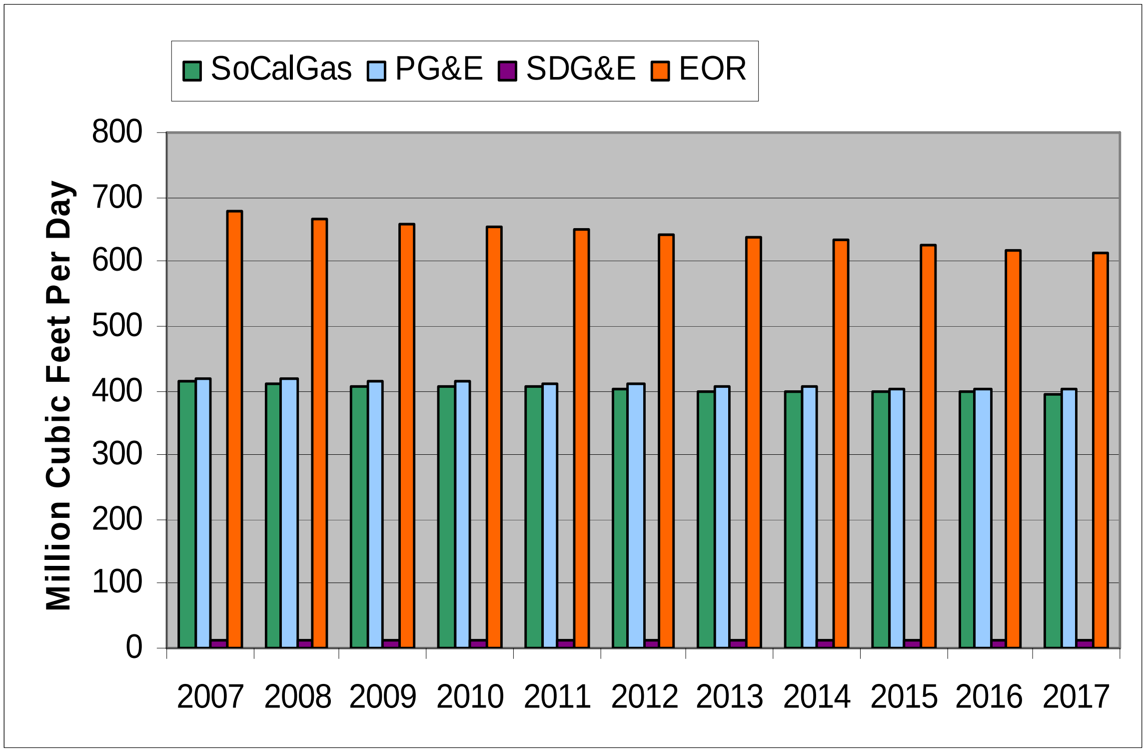


Source: Energy Commission Staff, 2007

*Forecast Demand

Commercial Sector	2007	2017	Annual change
SoCalGas	292	347	1.8 %
PG&E	230	276	1.9 %
SDG&E	52	63	2.0 %

Figure 12: California Utilities' Service Territories: Natural Gas Demand – Industrial*
(Million Cubic Feet per Day)

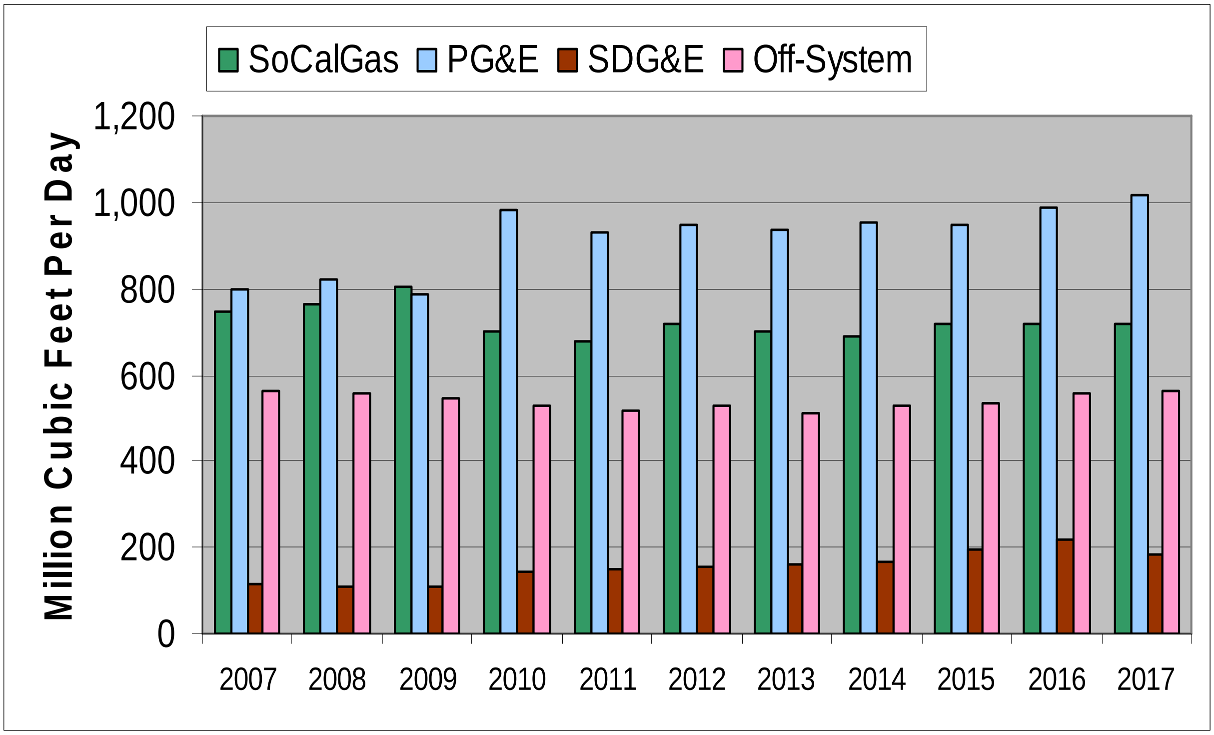


Source: Energy Commission Staff, 2007

*Forecast Demand

Industrial Sector	**2007**	**2017**	**Annual change**
SoCalGas	415	395	-0.4 %
PG&E	415	400	-0.4 %
SDG&E	15	15	-0.3 %
Enhanced Oil Recovery	675	611	-1.0 %

Figure 13: California Utilities' Service Territories: Natural Gas Demand for Power Generation*
(Million Cubic Feet per Day)



Source: Energy Commission Staff, 2007

*Forecast Demand

Power Generation Sector	2007	2017	Annual Change
SoCalGas	750	720	-0.4 %
PG&E	800	1,015	2.5 %
SDG&E	115	185	4.9 %
Off-System	560	565	0.1 %

Chapter 3: Natural Gas Supply

Natural gas supply projections are based on the World Gas Trade Model/NARG. The current model contains the most recent information available on North America's natural gas resources. The starting point for the estimate of natural gas resource costs was the work done by a team of geoscientists and modelers as part of the 2003 National Petroleum Council study titled: *Balancing Natural Gas Policy*. The developers of the NARG model updated these resource cost curves in 2006 to reflect accelerating exploration and development costs.

Significantly, in consideration of the results of recent explorations, a 16 trillion cubic foot (Tcf) field was removed from the mid-continent and a 16 Tcf field was also removed from the Rocky Mountain cost curves. These reductions support the phenomenon that, while the U.S. is drilling at a very high rate, production is not increasing. In addition, gas from Arctic Canada and the Alaska North Slope is not expected to be available during the forecast period.

Major Findings

Major findings regarding natural gas supply are:

- North America's natural gas production is projected to decline during the forecast period, by about 0.5 percent on an annualized basis or 5 percent for the 10 year period.

- Natural gas from Arctic Canada and from Alaska's North Slope is assumed to be unavailable during the forecast period.

- U.S. natural gas production is also projected to decline during the forecast period, falling annually by about 0.5 percent or 5 percent overall.

- The forecast projects that North America's natural gas supplies would be augmented by LNG imports, increasing from 3,072 MMcf per day in 2007 to 24,404 MMcf per day in 2017.

- The amount of gas produced in the Southwest, entering California at Blythe gradually decreases during the forecast period as natural gas imported from Mexico (Costa Azul Facility) displaces domestic production from the Southwest.

- Importation of LNG is expected from Mexico into San Diego through the Transportadora De Gas Natural De Baja California (TGN) pipeline beginning in 2009. Gas imported from Costa Azul is projected to grow from zero to more than 1,500 MMcf per day by 2017.

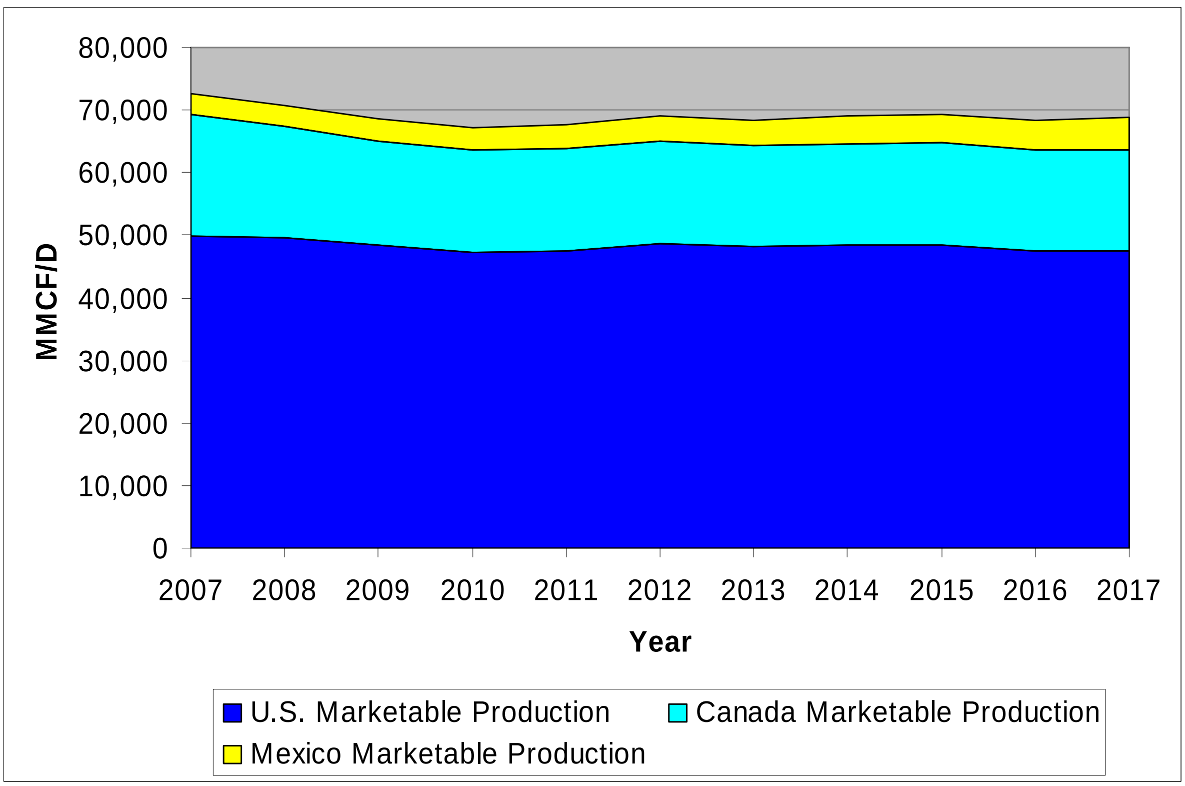
- From 2002 through 2007 the Energy Information Administration (EIA) has revised downwards its natural gas production forecasts.

- U.S. production has been relatively flat for the last several years even though natural gas prices and the number of natural gas wells drilled annually have both increased dramatically.

Supply Forecast Results

Figures 14 through 22 present model results for natural gas supply. Narrative directly below the figure provides further explanation or elaboration of the results.

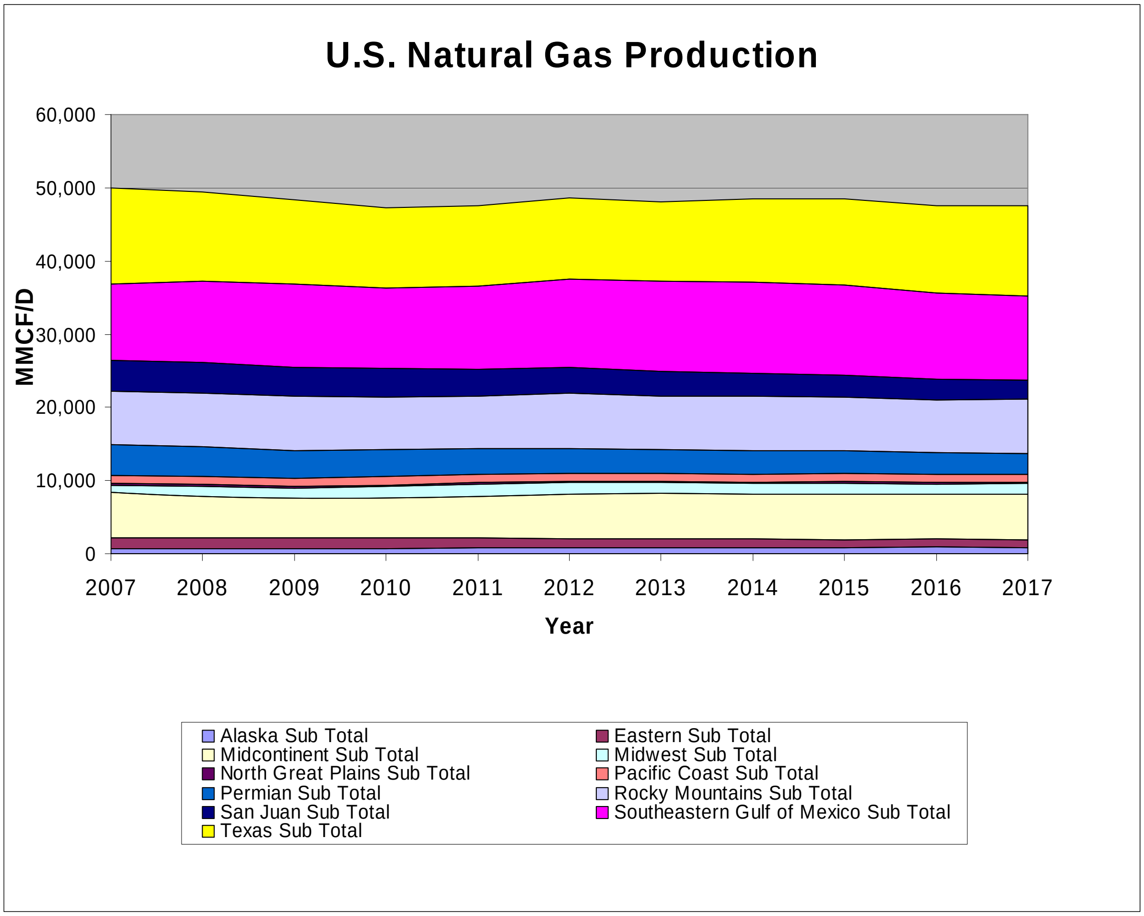
Figure 14: North American Natural Gas Production (MMcf per Day)



Source: Energy Commission Staff, 2007

North American natural gas production is projected to decline by approximately 0.5 percent on an annualized basis or 5 percent overall during the forecast period (Figure 14). Neither Alaska North Slope nor Mackenzie Delta production in Northern Canada is assumed to begin gas deliveries during the forecast period. Mackenzie production is expected to begin in 2020, and Alaska North Slope is slated to begin delivery in 2022.

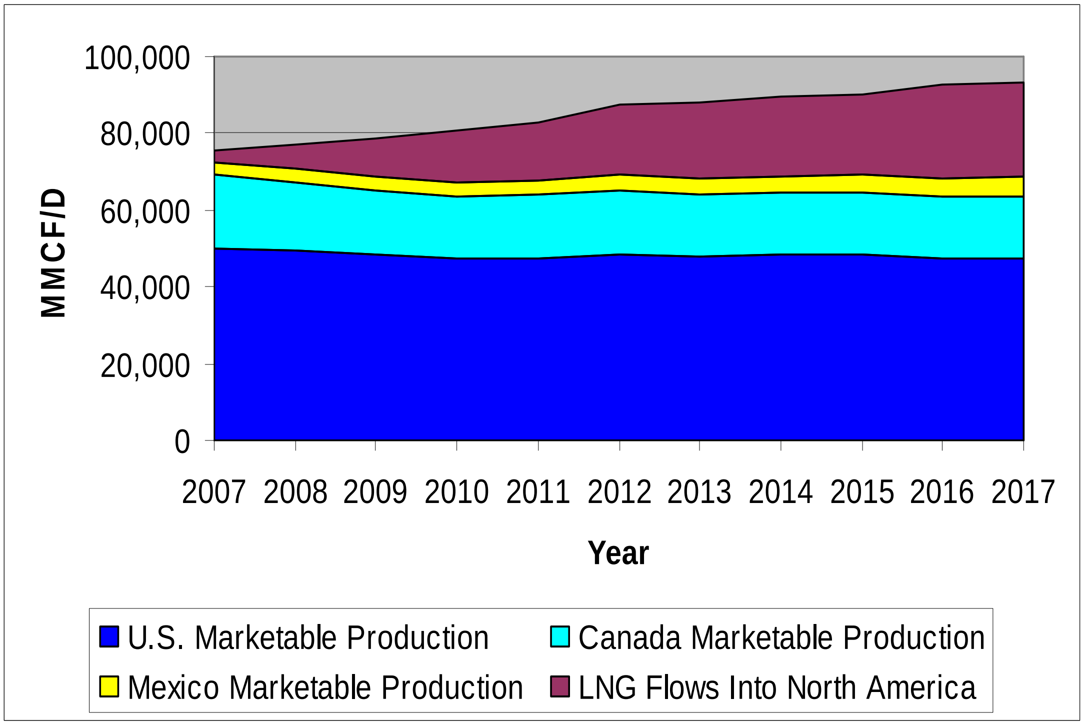
Figure 15: U.S. Natural Gas Production (MMcf per Day)



Source: Energy Commission Staff, 2007

U.S. natural gas production is also in decline during the forecast period, falling by about 0.5 percent per year or 5 percent overall (Figure 15). The flat production forecast is at odds with the increasing production forecast from Energy Information Administration (EIA.) However, based on flat production and despite recent high levels of drilling, the flat production scenario currently appears to be most realistic.

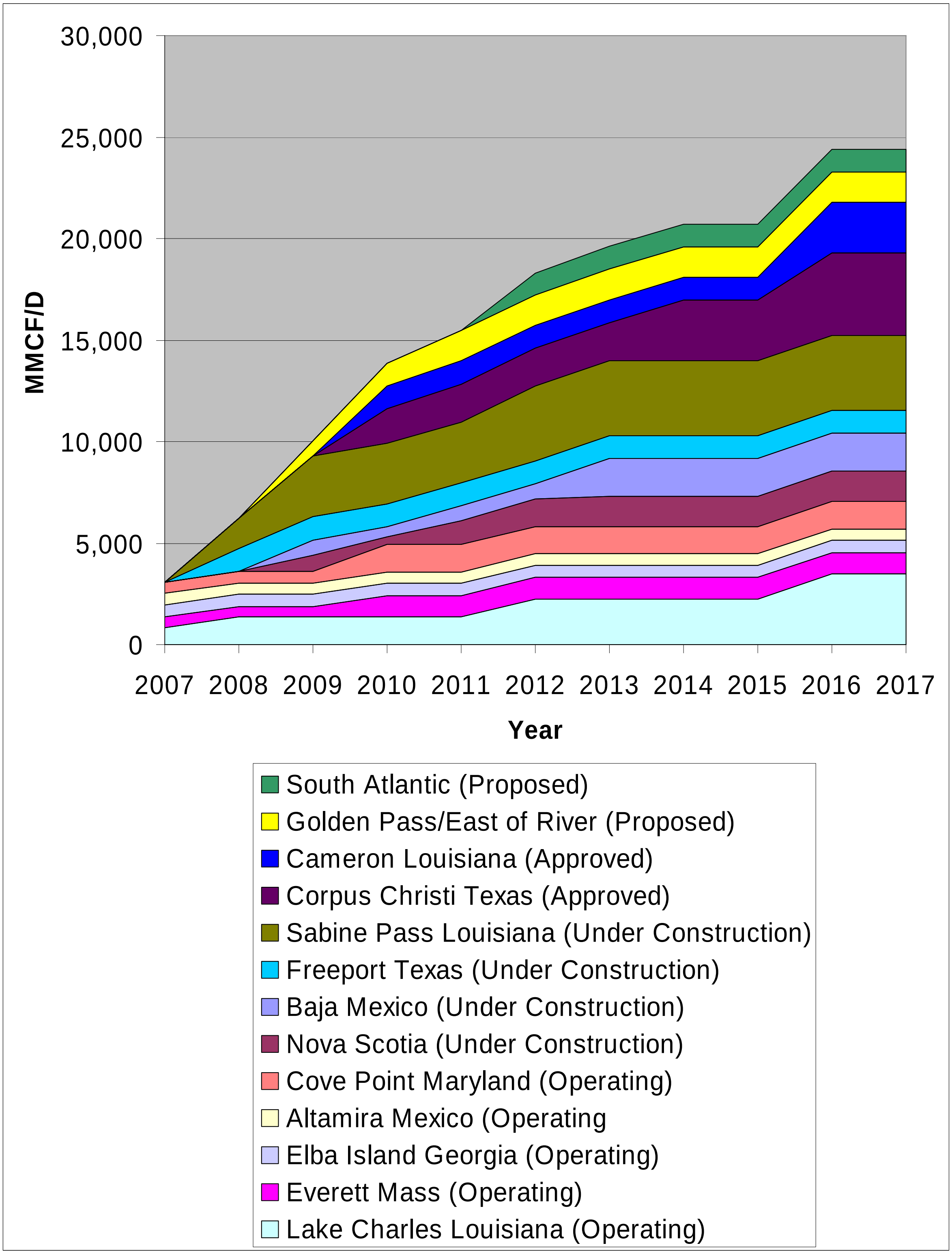
Figure 16: North American Natural Gas Supply



Source: Energy Commission Staff, 2007

Modeling results project that North American supply could be augmented by liquefied natural gas (LNG) imports, increasing from 3,072 MMcf per day in 2007 to 24,404 MMcf per day in 2017 (Figure 16). This represents a 23 percent annual increase or a 694 percent increase over the forecast period. The dramatic increase in the quantity of LNG imported into North America is the result of declining indigenous production and delays in construction of pipelines from both the Mackenzie Delta in northern Canada and Alaska North Slope. LNG is the resource expected to supplement domestic production to meet projected demand.

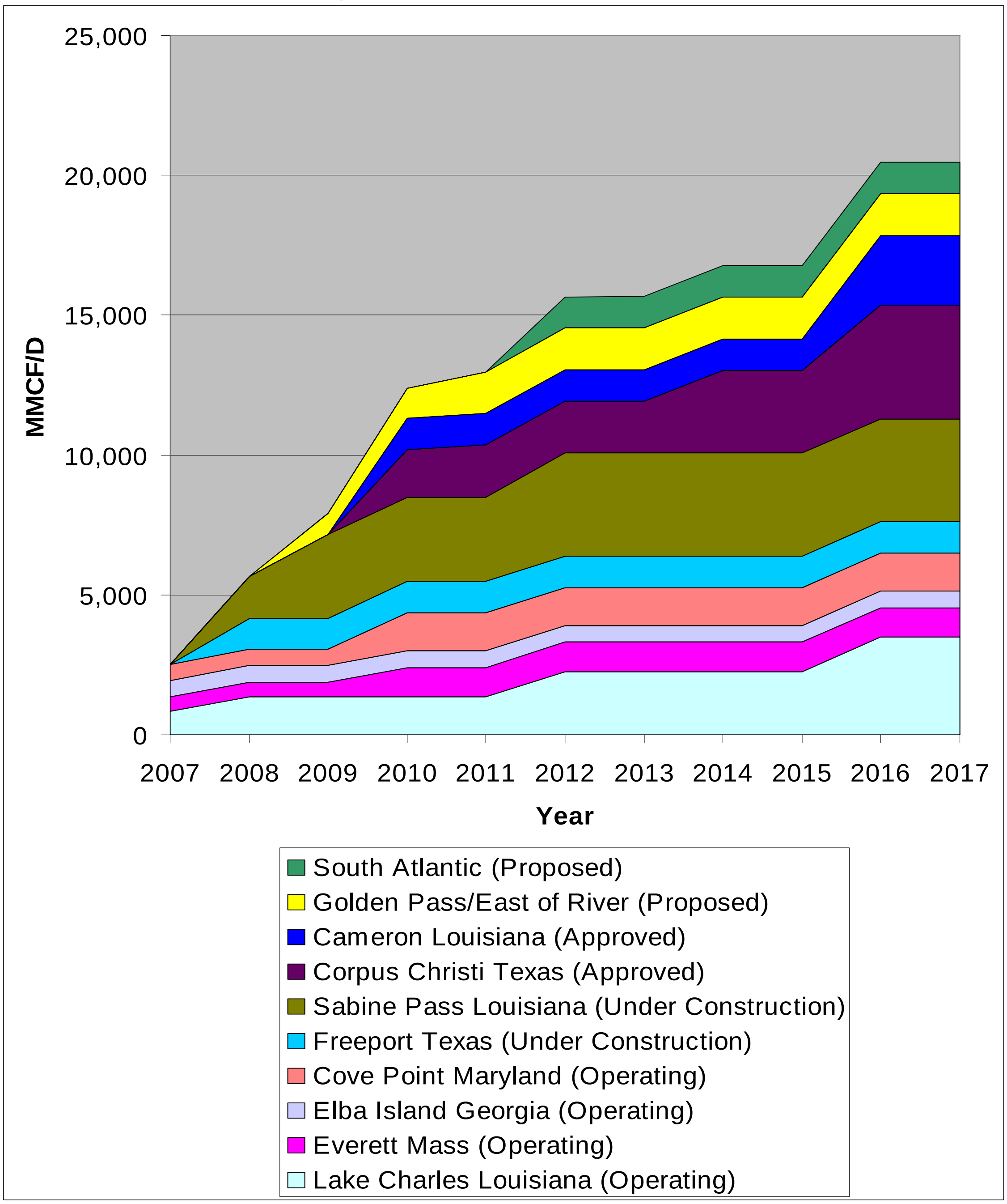
Figure 17: North American LNG Imports



Source: Energy Commission Staff, 2007

As shown in Figure 17, the majority of the LNG projected, by the Energy Commission's modeling, for importation into North America flows into the Gulf of Mexico. LNG could only be imported into Canada on the east coast. In Mexico, there is one facility on the east coast already operating, and there is one under construction, Costa Azul, on the west coast in Baja, California. In 2013, the model assumes an expansion of this facility.

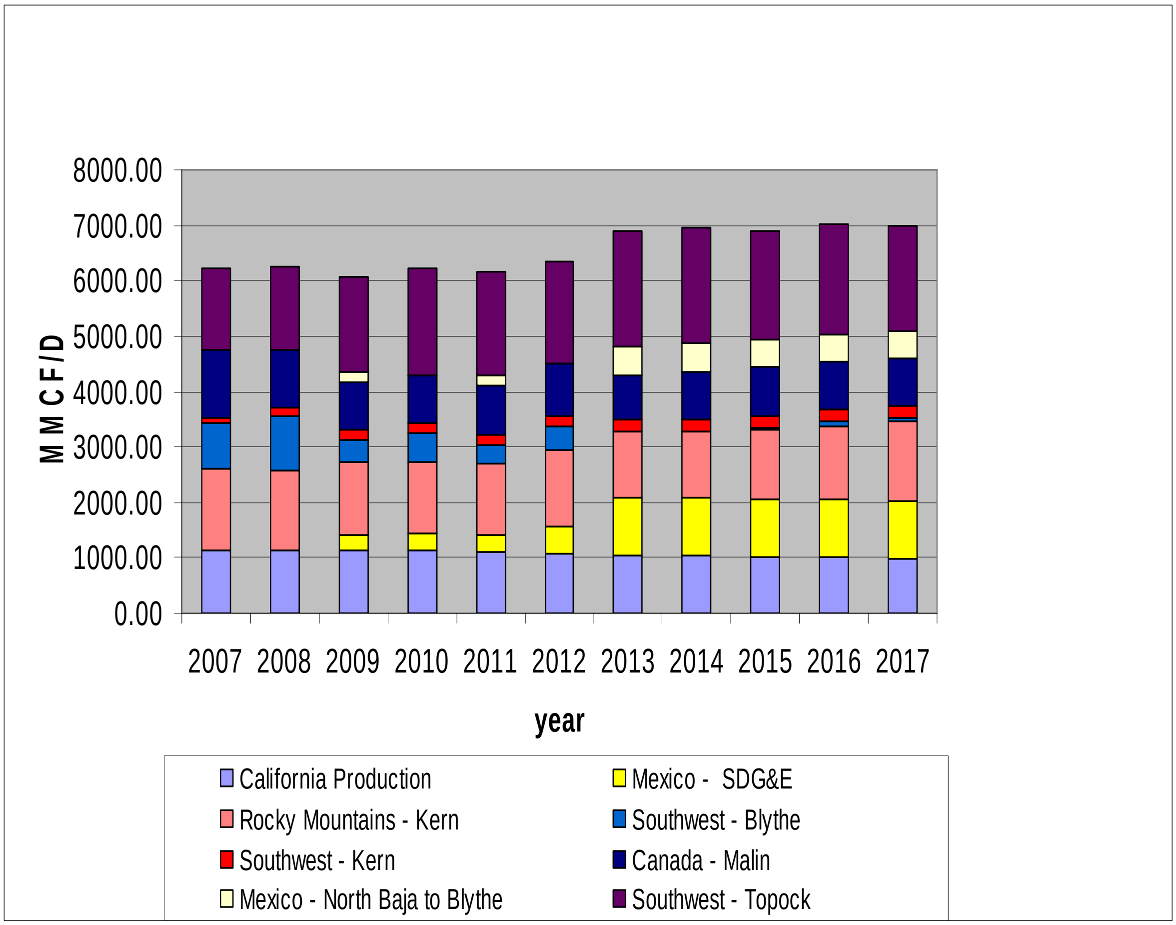
Figure 18: U. S. LNG Imports



Source: Energy Commission Staff, 2007

U.S imports of LNG are also projected in this forecast to increase significantly: 23 percent annually and 716 percent overall (Figure 18). As noted above, the majority of LNG is projected to come into the Gulf Coast, with the remaining into the east coast. Because the reference case assumes that no new LNG terminals are built on the west coast during the forecast period, no imports of LNG occur on the west coast of the United States.

Figure 19: Sources of Natural Gas Supply for California[1]



Source: Energy Commission Staff, 2007

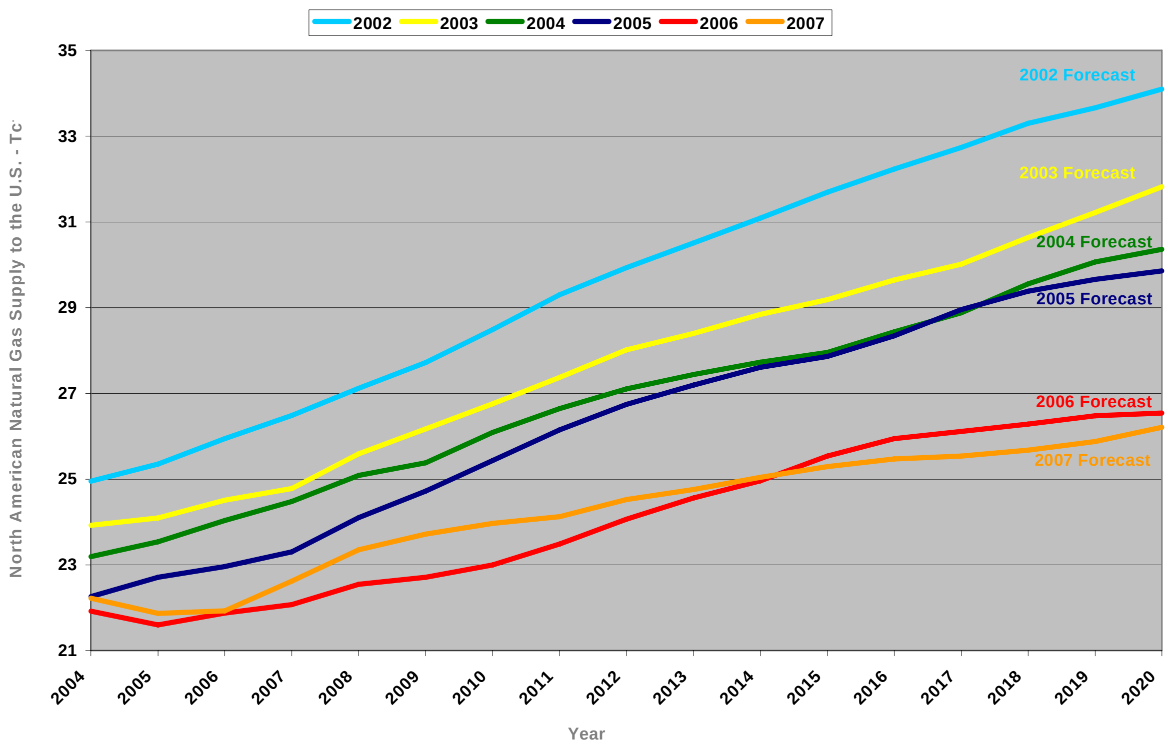
Natural gas produced in the Southwest, entering California at Blythe, is projected in the reference case to diminish gradually during the forecast period as gas imported from Mexico displaces domestic production from the Southwest (Figure 19). Imports from Canada could also fall from about 1,100 MMcf per day to about 651 MMcf per day. Importation of LNG is also expected from Mexico into San Diego through the

[1] The model balances supply and demand in all regions and in all time periods. Therefore, the model results account for pipeline losses. The differences between Figure 19 and Figure 4 (California Natural Gas Demand) represent these losses.

TGN pipeline beginning in 2009. Gas imported from Mexico is projected to grow from 0 to over 1,500 MMcf per day by 2017 in order to meet demand.

Supply from the Rocky Mountains remains relatively constant throughout the forecast period. In 2009, however, when the Rockies Express pipeline begins operation, flows from the Rockies are predicted to decline by about 200 MMcf per day and may not return to pre-2009 levels until 2012.

Figure 20: DOE EIA Natural Gas Production Forecasts

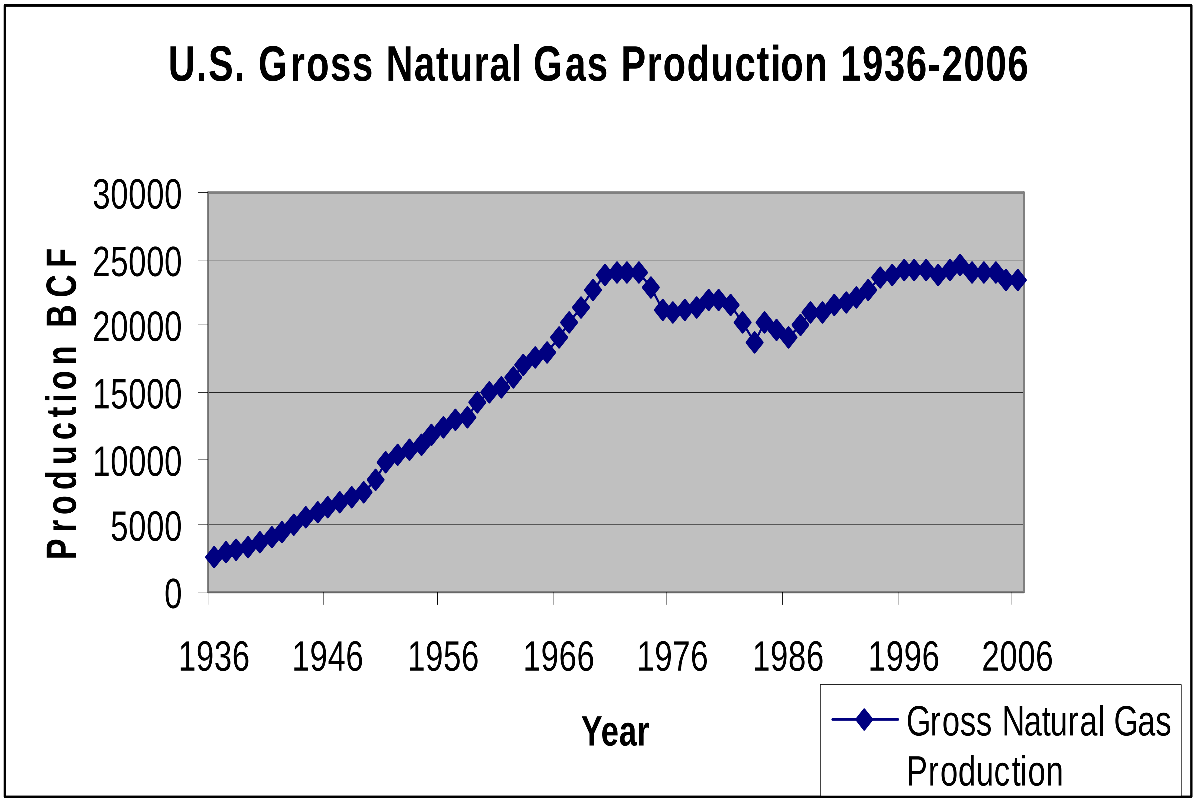


Source: EIA Annual Energy Outlook, 2001 through 2007

EIA's natural gas supply forecasts have been revised downward in each *Annual Energy Outlook* report since 2002 (Figure 20). These downward revisions reflect the realization by industry and government that the supply of natural gas in North America is not as large as previously thought.

The supply of natural gas in North America has recently been the subject of much speculation. The reliability of domestic and Canadian supplies is a key factor to understand the future natural gas market in North America. There are many indications that North American supplies are not sufficient to meet demand and that alternative sources of natural gas will be needed in the forecast period.

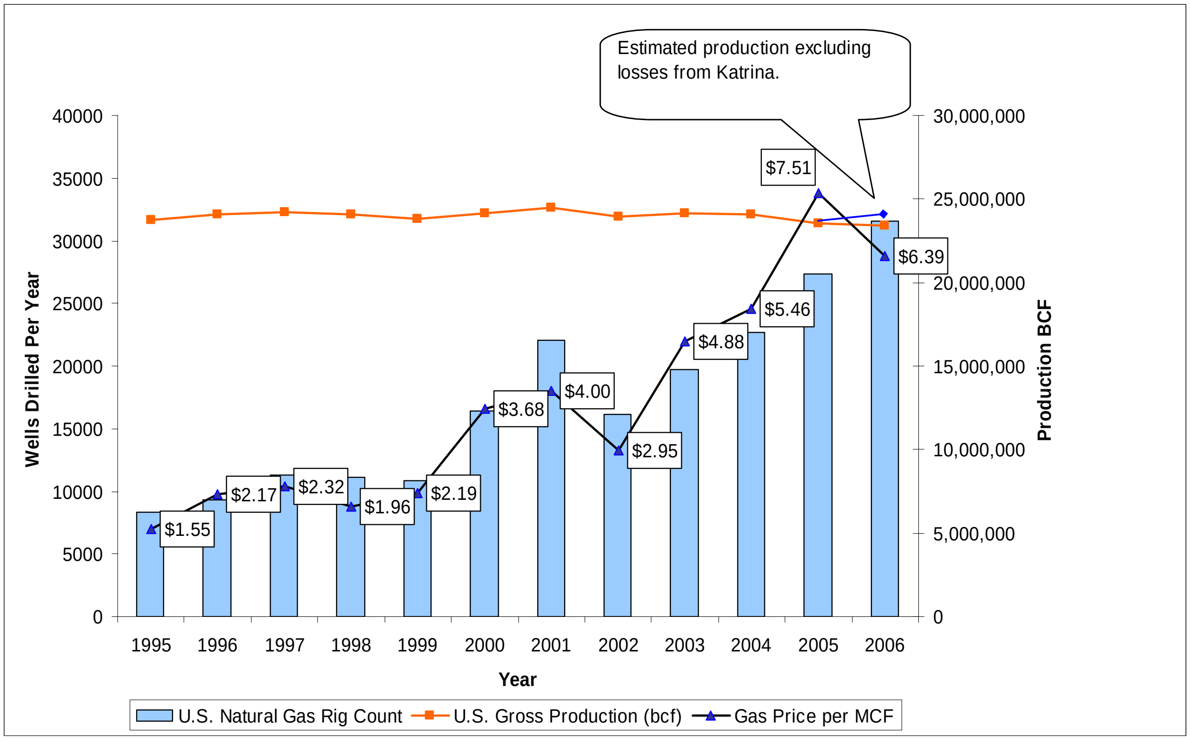
Figure 21: U.S. Gross Natural Gas Production 1936–2006



Source: EIA

Annual gross natural gas production first peaked in 1971 at 24,088 Bcf, in tandem with oil production (Figure 21). Since then, it declined through the early 1990s before rising steadily and peaking again at an all-time high in 2001 at 24,501 Bcf. Much of this increase was due to the increase in unconventional production such as coal bed methane and shale gas. Since 2001, production has been in a slight decline.

Figure 22: Production, Price, and Number of Natural Gas Wells Drilled



Source: EIA

Since 1995, the price of natural gas (in nominal dollars) has risen and the number of wells drilled per year rose from about 8,400 to over 31,000. In stark contrast, gross production has remained flat to slightly declining. However, there are some indications that production is beginning to respond to the increased drilling. Estimated 2006 production losses from the 2005 hurricanes are approximately 0.5 to 0.75 Tcf. Adding back those estimated production losses suggests a slight rise in 2006 production. However, an accurate assessment of the amount that production can be increased will not be possible until data from the next few years is analyzed. Natural gas prices in nominal and $2006 dollars:

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Nominal$	$1.55	$2.17	$2.32	$1.96	$2.19	$3.68	$4.00	$2.95	$4.88	$5.46	$7.51
2006$	$1.95	$2.68	$2.82	$2.35	$2.59	$4.26	$4.52	$3.28	$5.32	$5.80	$7.76

CHAPTER 4: NATURAL GAS INFRASTRUCTURE

This section of the report examines the impact on the natural gas infrastructure portfolio during the forecast horizon, 2007 to 2017. Natural gas pipelines serving California are illustrated in Appendix B.

Major Findings

Major findings with respect to natural gas infrastructure:

- During the forecast period, the assessment results show that all major pipeline systems serving California operate at less than 100 percent capacity factors. For example, Kern River's capacity utilization hovers around 80 percent throughout the forecast horizon, while all other pipeline systems fall below 50 percent.

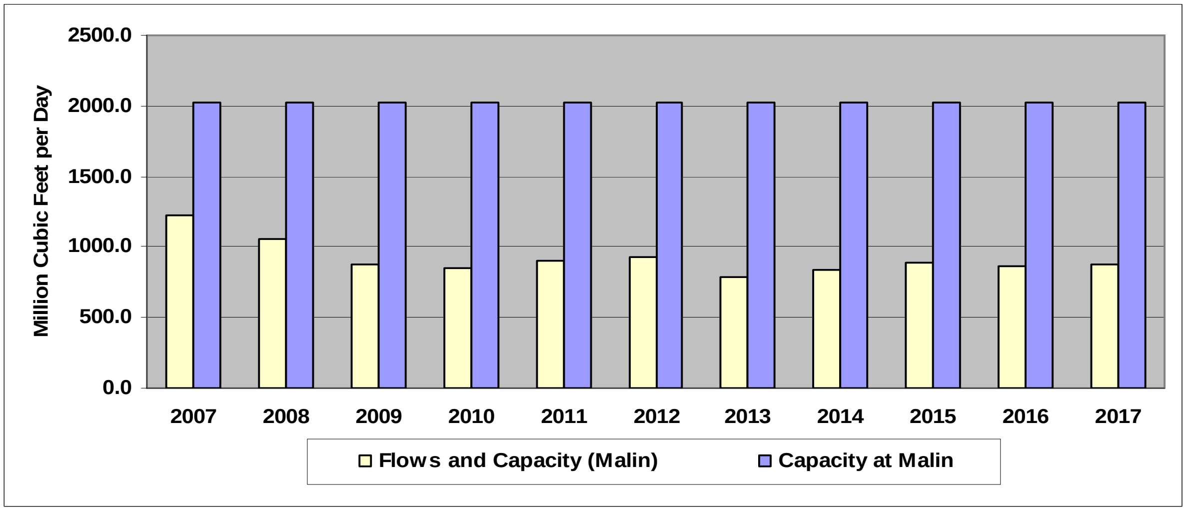
- The results project that LNG entering California could displace natural gas from the Southwest.

- The assessment projects that only two pipelines affecting California could expand. The pipelines, TGN southbound and North Baja westbound, now deliver conventional natural gas to their end users. However, after Costa Azul begins operations, both pipelines will reverse and expand to accommodate the flow of regasified LNG. TGN northbound flows gas into San Diego and North Baja eastbound flows gas into Blythe/Ehrenberg.

Infrastructure Forecast Results

Figures 23 through 28 present model results relating to natural gas infrastructure. Narrative directly below the figure provides further explanation or elaboration of the results.

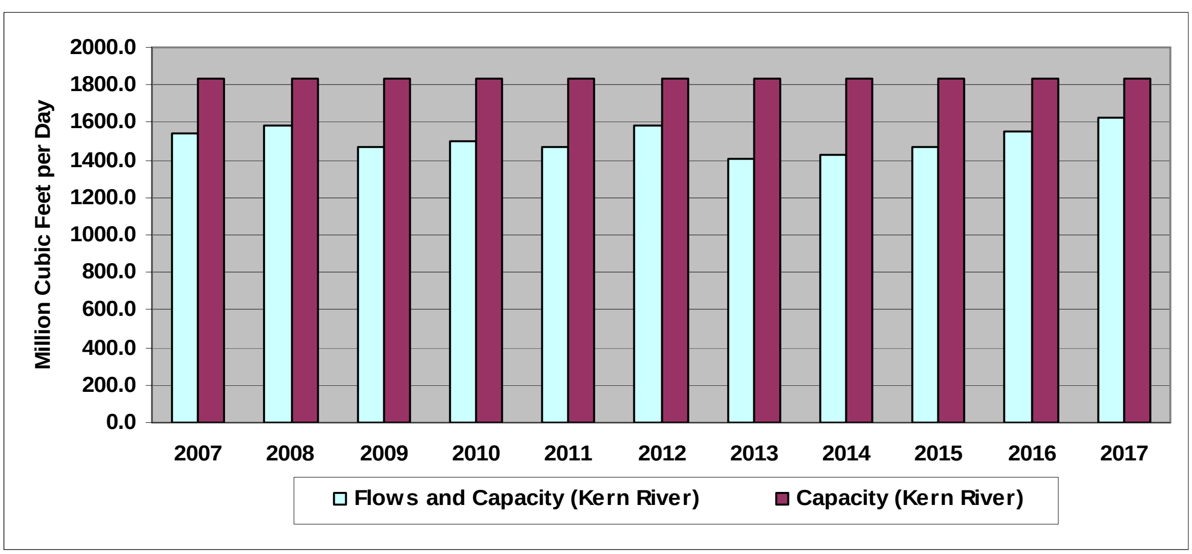
Figure 23: Flows and Capacity at the California Border (Malin)



Source: Energy Commission Staff, 2007

Figure 23 shows projected gas flows and capacity at Malin, Oregon. Natural gas from the Western Canadian Sedimentary Basin reaches Malin through the Gas Transmission Northwest pipeline. Available capacity at Malin is about 2,190 MMcf per day. Natural gas then enters the Pacific Gas and Electric Company (PG&E) system and travels along PG&E's Redwood Path, which can handle maximum flows of around 2,021 MMcf per day. However, during the forecast horizon, capacity utilization is projected to decrease, falling from approximately 60 percent in 2007 to about 43 percent in 2017.

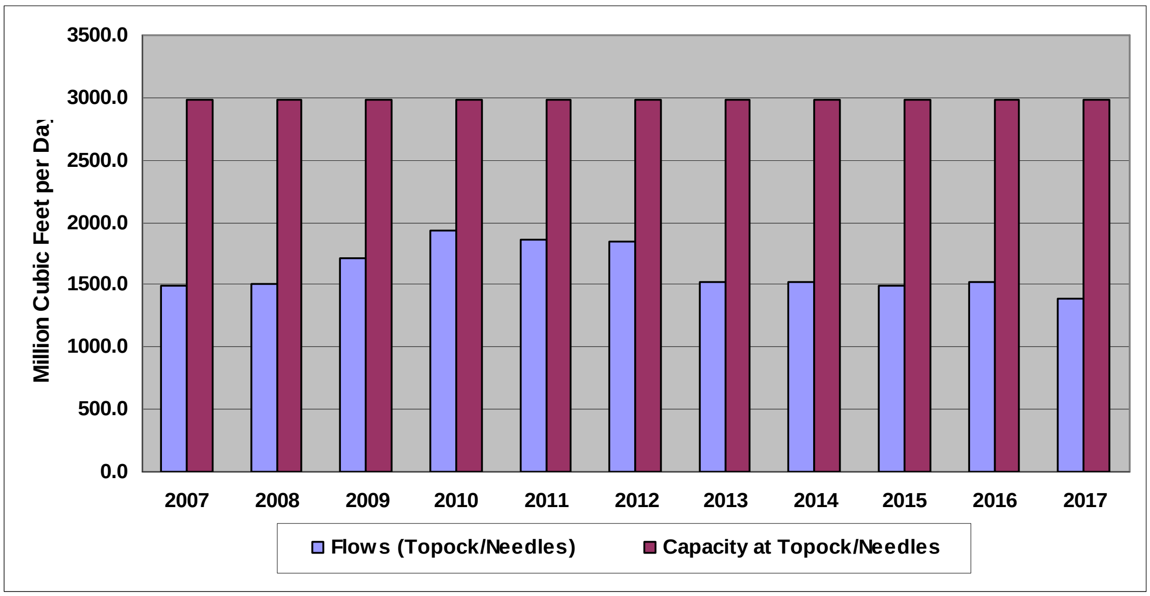
Figure 24: Flows and Capacity at the California Border (Kern River)



Source: Energy Commission Staff, 2007

Figure 24 shows gas flows and capacity along the Kern River pipeline system. Natural gas from the Rocky Mountain Basin reaches California through the Kern River pipeline. Available capacity along the California leg is about 1,830 MMcf per day. Natural gas from this source serves the enhanced oil recovery industry and other markets in California. During the forecast horizon, capacity use is projected to remain stable, averaging nearly 80 percent. Rocky Mountains gas, which, in California, mostly serves the enhanced oil recovery industry and other large end-users, maintains a competitive edge when compared with other natural gas sources. As a result, Kern River capacity use factors remain relatively high.

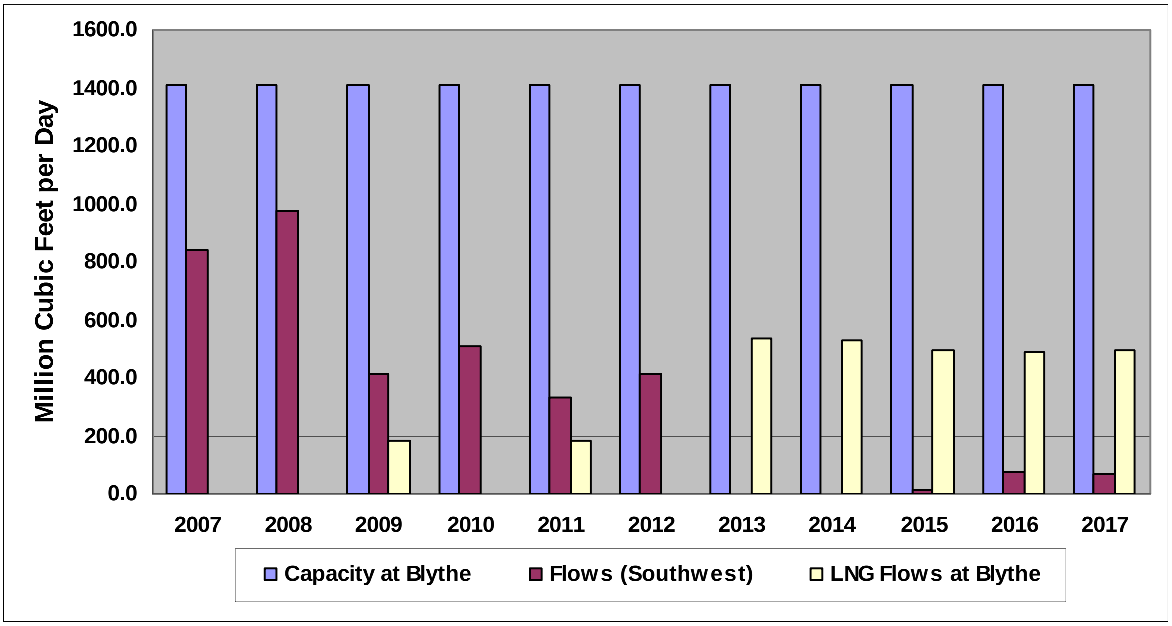
Figure 25: Flows and Capacity at the California Border (Topock)



Source: Energy Commission Staff, 2007

Figure 25 shows the gas flow and capacity at Topock, California, on the Colorado River. California receives natural gas from the San Juan Basin through three pipeline systems: El Paso North, Transwestern, and Southern Trails. In the first half of the forecast horizon, the combined utilization of these pipelines rises, averaging about 62 percent in 2012. However, after 2013, capacity utilization falls to about 50 percent. This is a result of an assumed increase in LNG terminal capacity at Costa Azul.

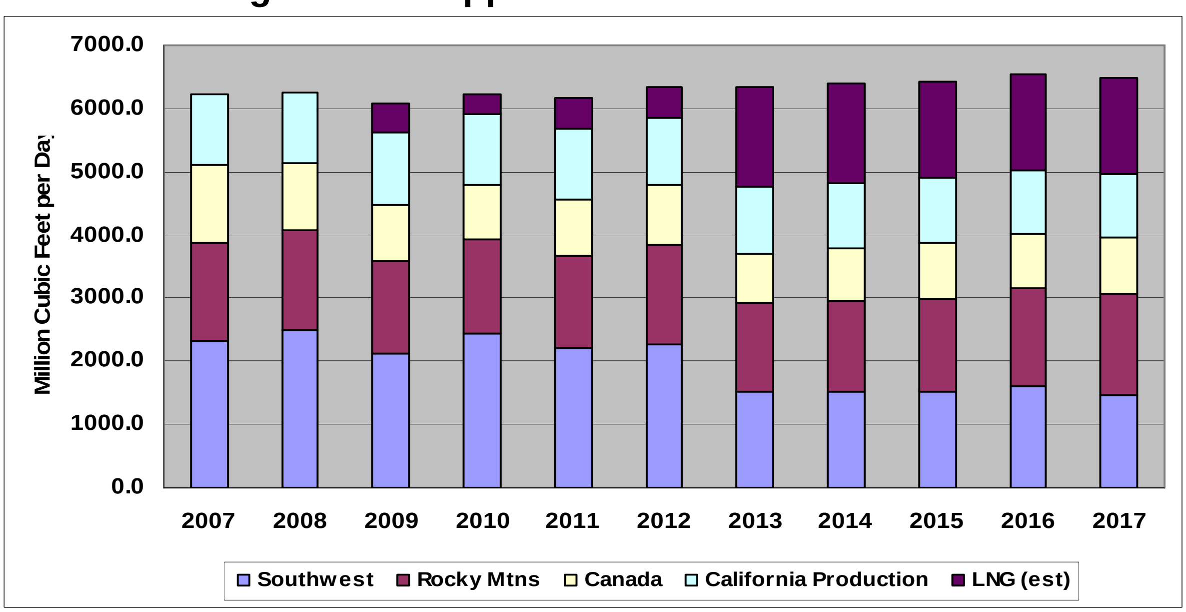
Figure 26: Flows and Capacity at the California Border (Blythe)



Source: Energy Commission Staff, 2007

California receives natural gas from the Permian Basin through the El Paso South pipeline system. However, during the forecast horizon, model results project that regasified LNG would displace Southwest natural gas and dominate natural gas flows at Blythe (Figure 26). However, regasified LNG reaches Blythe via North Baja eastbound. Capacity utilization for Southwest natural gas declines and hovers around zero by the end of the period. However, LNG flows increase during the same period.

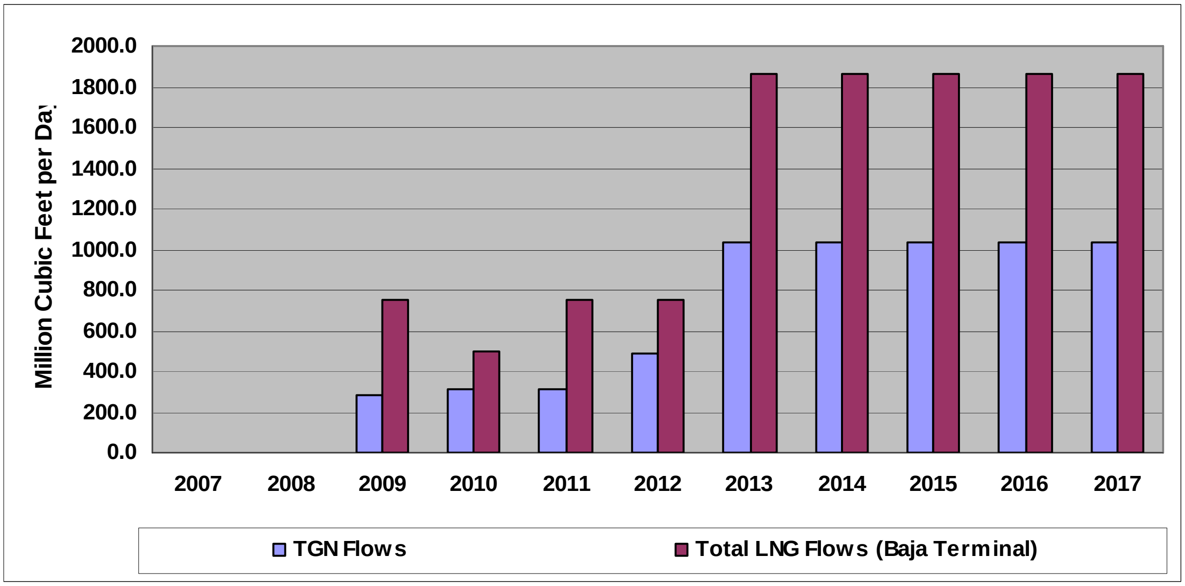
Figure 27: Supplies Available to California



Source: Energy Commission Staff, 2007

Figure 27 shows why the current pipeline systems deliver gas to California at capacity factors below 100 percent, and sometimes below 50 percent. As LNG flows from Baja Mexico increase, Southwest flows along El Paso North, El Paso South, Transwestern, and Southern Trails decrease. As a result, regasified LNG from Mexico displaces natural gas from the Southwest**.**

Figure 28: LNG Flows from Terminal



Source: Energy Commission Staff, 2007

Figure 28 shows LNG flow from the Costa Azul terminal in Baja Mexico. LNG reaches California via two routes: TGN northbound and North Baja eastbound. The model assumes that an expansion of existing terminal capacity is the most logical and economic way to increase natural gas supply in the system in order to meet demand. As a result, the comparatively lower costs for LNG are projected to increase flows in 2013.

Table 2: Capacity Expansion on Pipelines Affecting California

Capacity Expansion, MMcf per day		
	TGN Northbound	**North Baja Eastbound**
2007	0.0	0.0
2008	0.0	0.0
2009	179.4	0.0
2010	36.9	0.0
2011	0.0	0.0
2012	720.1	351.6

Source: California Energy Commission Staff Assessment

During the forecast horizon, capacity expansions are projected on two pipelines that affect California. Table 2 shows that in order to deliver LNG from the Costa Azul terminal into California, TGN northbound must expand by over 900 MMcf per day, mostly occurring in 2012. North Baja eastbound also expands by over 350 MMcf per day in 2012.

The projected excess capacity on the interstate pipelines serving California is based on average hydro conditions. In the event that a severe drought on the West Coast reduces hydroelectric generation, all or part of that excess capacity would be needed to meet the increased demand by natural gas fired electric generators.

CHAPTER 5: NATURAL GAS PRICES

This chapter focuses on natural gas prices in the West, with some attention on other regions. The chapter identifies and discusses detected shifts in the natural gas market and evaluates the basis spread[2] during the forecast horizon. The basis spread evaluation compares the prices at selected hubs—Chicago City Gate, New York, Opal, AECO, Malin, and the Southern California border—with prices at Henry Hub, located in Louisiana. Price projections are in $2006 dollars unless otherwise noted.

Major Findings

Major findings of staff's natural gas price assessment include:

- The model projects prices to fall early in the forecast period, and then rise to nearly $7 per Mcf by 2017.

- Over the next 10 years, more available supply options could increase gas-on-gas competition.

- Basis spreads between Henry Hub (Louisiana) and other hubs increase during the forecast period. This implies that the Henry Hub price is not rising in lock step with other North American hubs and remains low because the majority of expected imported LNG coming into the Gulf Coast is close to Henry Hub.

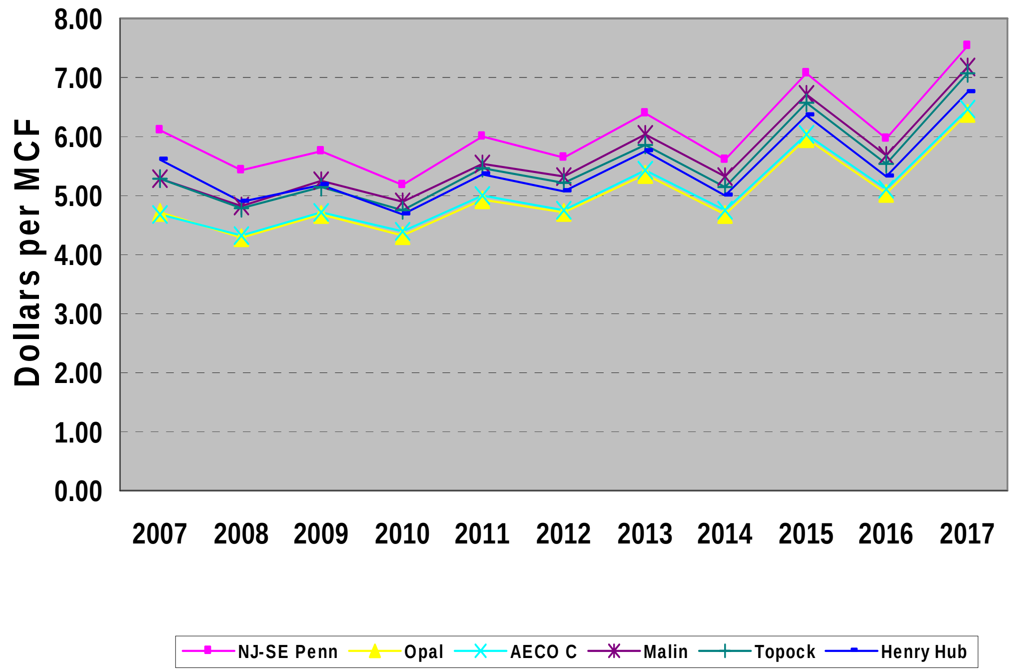
- The basis spreads, that traditionally were negative, become positive. The discount that California has enjoyed relative to Henry Hub becomes a premium.

Price Forecast Results

Figures 29 and 30 present staff's preliminary expected natural gas price forecast. Narrative accompanying the figures provides further explanation or elaboration of the results.

[2] Basis spreads are the difference between prices at two different locations. The comparison is typically made between prices at a given location versus Henry Hub.

Figure 29: Average Annual Hub Prices in 2006 Dollars per Mcf



Source: California Energy Commission

Figure 29 shows the forecasted prices for selected hubs. There is a relatively constant basis differential throughout the forecast horizon. However, the slight tightening of spreads at the end of the study horizon means that the demand centers have more options to select their needed supplies. The initial drop in prices reflects an assumed increase of LNG flows into the U.S.

Over the next 10 years, more available supply options will increase gas-on-gas competition. This begins with building new pipeline capacity to connect supply regions with demand centers. With the addition of pipelines like the Rockies Express, land-locked supply regions are opened up to new markets. LNG facilities add to the supply mix.

Table 3: Annual Average Natural Gas Basis Differentials

	Chicago	New York	Kern/Opal	AECO	Malin	SoCal
Historical						
2003	0.10	0.61	(1.13)	(0.78)	(0.68)	(0.63)
2004	(0.12)	0.73	(0.82)	(0.89)	(0.56)	(0.43)
2005	0.12	1.42	(1.30)	(0.81)	(0.82)	(0.31)
2006	0.32	0.84	(1.47)	(0.10)	(0.38)	(0.35)
Forcasted						
2006	(0.11)	0.58	(0.97)	(1.28)	(0.40)	(0.39)
2007	(0.03)	0.51	(0.88)	(0.93)	(0.31)	(0.31)
2008	0.11	0.52	(0.60)	(0.59)	(0.06)	(0.11)
2009	0.17	0.57	(0.51)	(0.48)	0.05	(0.03)
2010	0.24	0.52	(0.36)	(0.30)	0.21	0.09
2011	0.25	0.62	(0.43)	(0.38)	0.19	0.08
2012	0.29	0.58	(0.36)	(0.30)	0.26	0.15
2013	0.33	0.64	(0.40)	(0.32)	0.28	0.10
2014	0.30	0.59	(0.33)	(0.25)	0.30	0.13
2015	0.37	0.72	(0.41)	(0.32)	0.36	0.20
2016	0.36	0.65	(0.29)	(0.21)	0.39	0.24
2017	0.44	0.78	(0.36)	(0.29)	0.42	0.31

( ) indicates a negative number
Source: *Natural Gas Week*

Historical and forecasted price spreads are shown in Table 3. The historical basis spreads are based on annual average hub prices for the indicated locations, as published by *Natural Gas Week,* and are expressed in 2006 dollars.[3]

Both historical and forecasted spreads are given for 2006. The forecasted basis differentials compare very favorably with actual recorded spreads. Except for AECO, they are all near or in the range of recent differentials. Even the AECO differential is not significantly different from 2003–2005. Except for Malin and at the Southern California border, positive prices remain positive and negative prices remain negative. For California, this means that around the year 2010 the state could no longer be in the favorable position of having its border prices lower than the Henry Hub price.

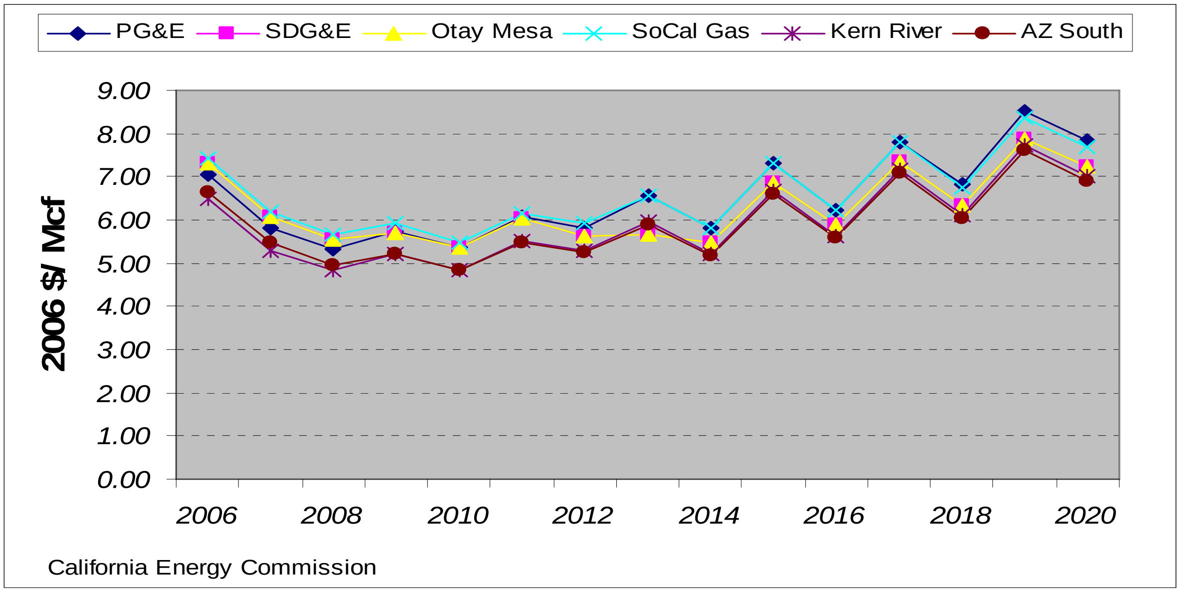
There was some concern that when the Rocky Mountain Express Pipeline goes into operation in 2009, a shift might occur in the basis spread at Opal. But as Table 3 indicates, little or no shift is evident from the new pipeline's operation.

All the basis spreads between Henry Hub and other hubs are increasing. This implies that the Henry Hub price is not rising as fast as the other hubs in the U.S.

[3] California Energy Commission's May 30, 2005 deflator series was used to convert historical prices to constant 2006 dollars.

and Canada. Influencing this is the landing of nearly all new LNG supply in the Gulf Coast, near Louisiana, where the Henry Hub is located. This new supply tends to dampen price increases in the area. The regional market phenomenon of transport cost and supply mix lead to faster hub price rises than at Henry Hub.

Figure 30: Forecasted Electric Generation Natural Gas Prices



Source: Energy Commission Staff, 2007

Natural gas prices follow general price trends with some regional differences. Figure 30 shows electric generation natural gas prices for 6 of the 32 fuel group price forecasts.[4] Both Kern River and the Arizona South fuel groups receive natural gas directly off interstate pipelines. The prices for these two fuel groups are lower than the prices for California utility power plants. In the long term, there is very little difference in generation prices in the Southern California Gas (SoCalGas) and PG&E service areas. Before the Baja LNG facility is built, SDG&E prices are the same as in the SoCalGas system. When the LNG facility becomes available, SDG&E prices more closely resemble interstate service. That utility is closer to the supply source than other utilities in California, and its overall transport costs are therefore lower.

Historical price forecasts of the California Energy Commission and the EIA are shown in Appendix C – Historical Price Forecasts.

[4] For electricity resource analysis, the Energy Commission has assigned all existing and new power plants to 1 of 32 "fuel groups." These are based on location and whether they receive service directly from an interstate pipeline or from a utility.

CHAPTER 6: SENSITIVITIES

This *2007 Natural Gas Assessment* expands the analysis of the natural gas system by constructing four sensitivities. Each sensitivity begins with the base case, changes a single model input parameter, and examines the impact on natural gas prices or supplies. The four sensitivities are:

1. Increase the base case oil price projection ($50 per barrel in 2017) to a sustained high oil price projection ($67 per barrel in 2017).

2. Reduce the base case oil price projection ($50 per barrel in 2017) to a sustained low oil price projection ($38 per barrel in 2017).

3. Add a 1 Bcf per day LNG regasification terminal in Southern California, operation beginning in 2011.

4. Add a 1 Bcf per day LNG regasification terminal in the Pacific Northwest, operation beginning in 2013.

Major Findings

The major findings of the NARG Sensitivity runs are as follows:

- Raising the oil price beyond the projection of the base case produces no noticeable changes in the natural gas price.

- Lowering the oil price beyond the projection of the base case produces a natural gas price decrease. Though persisting throughout the forecast horizon, the price decrease was within the model's precision.

- An LNG regasification terminal with a capacity of 1 Bcf per day in Southern California displaces natural gas on the interstate pipelines serving California, which provided additional competition to domestic supplies of natural gas and could lower prices.

- An LNG regasification terminal with a capacity of 1 Bcf per day in the Pacific Northwest displaces natural gas flowing south from the Western Canadian Sedimentary Basin, but produces no noticeable price reduction in California.

Sensitivity Run Results

In the <u>High Sustained Oil Price</u> sensitivity, natural gas prices do not change as a result of a higher-than-the-base case oil price projection. The base case uses a relatively high oil price and all facilities that can switch between oil and natural gas would do so. However, as the level of oil prices rises, as this sensitivity assumes, natural gas demand remains unchanged, indicating that *no more* switching to oil occurs in North America. As a result, prices remain unchanged relative to the base case.

In the Low Sustained Oil Price sensitivity, the natural gas prices drop, indicating that oil prices are competing with natural gas prices in contestable markets. In this sensitivity, both effects of displacement of natural gas demand and depression of prices occur. This competition results in natural gas losing market share to oil, lowering demand and thus prices.

Table 4: Changes in Flows from Adding LNG in Southern California (MMCF per Day)

	2013	2015	2017
California Prod.	(3.50)	(2.84)	(2.01)
Canada – Malin	(26.12)	(25.55)	(2.11)
Mexico - SDG&E	(92.37)	(92.37)	(92.37)
Mexico - North Baja to Blythe	37.68	37.18	35.23
Rocky Mountains – Kern	(84.28)	(71.05)	(40.18)
Southwest – Blythe	0.00	(12.11)	(70.58)
Southwest – Topock	(575.14)	(416.79)	(421.04)

Source: Energy Commission Staff, 2007

Table 4 and Table 5 show the changes in flows as a result of adding a 1 Bcf per day terminal in Southern California or the Pacific Northwest. In the tables, a negative number means a reduction of flows relative to the base case. Table 5 shows that a 1 Bcf per day terminal in Southern California will “back out” supplies from the Southwest, both at Topock and Blythe. However, a 1 Bcf per day terminal in the Pacific Northwest increases supplies available to California at Malin and along Kern River.

The LNG terminal in Southern California increases gas-on-gas competition, placing downward pressure on prices after operation begins. However, this price reduction effect in California does not occur for a facility added in the Pacific Northwest. These two sensitivities suggest that the magnitude of the change of flow determines the level of the price impact. A terminal in Southern California pushes out as much as 750 MMcf per day. In addition, the lower prices stimulate small demand increases within California, which result in increased flows along pipelines such as the All-American westbound.

Table 5: Changes in Flows from Adding LNG in Pacific Northwest, MMcf per Day

	2013	2015	2017
California Prod.	(0.35)	(0.34)	(0.10)
Canada – Malin	133.82	130.66	142.33
Mexico - SDG&E	2.29	2.29	2.29
Mexico - North Baja to Blythe	(3.94)	(3.83)	(4.30)
Rocky Mountains – Kern	58.14	57.78	30.33
Southwest – Blythe	0.00	(12.11)	1.70
Southwest – Topock	(25.96)	(23.48)	9.80

Source: Energy Commission Staff, 2007

A terminal in the Pacific Northwest, however, produces a small increase, about 130 MMcf per day in 2015, in supplies available to California. An even smaller increase, about 58 MMcf per day in 2015, occurs along Kern River. These small changes in natural gas supplies to California produce little or no price changes.

Flows from an LNG terminal in the Pacific Northwest push out and commingle with Canadian supplies. At the Pacific Northwest Citygate, four markets -- Nevada, Idaho, Oregon, and Washington -- compete for the increased supplies.

CHAPTER 7: ALTERNATIVE CASES

The Energy Commission retained consultant R. W. Beck, Inc. to provide comments on the natural gas assessment's reference case assumptions, develop alternative assumptions designed to help evaluate different possible outcomes, and assist staff in reviewing its model outputs as part of its preparation for the *2007 Assessment*. It should be noted that R. W. Beck did not develop the reference case assumptions and may it produce forecasts that are different from those in the reference case. This section summarizes R. W. Beck's comments and presents the alternatives the company suggests that the Energy Commission and users of the natural gas price forecast and modeling output evaluate, albeit generally qualitatively, as they consider the analysis and its results.

Major Findings

Among these findings are two approaches for recognizing the uncertainty in predicting natural gas demand to develop low and high case demand assumptions: one quantitative that uses the distribution of recorded demand growth to create a range around the expected demand case and one qualitative that identifies the "bottoms-up" factors that could create higher versus lower demand. The quantitative analysis demonstrates that a reasonable high case could be 1.5 Tcf higher than staff's reference case.

The consultant additionally developed a heuristic tool to create a snapshot of natural gas supply that can ultimately be used to assess the supply/demand balance. This approach allows one to better understand the components of natural gas supply and how small changes in production per well or wells drilled, or supply from Canada, changes the U.S. supply/demand balance.

The high supply case assumes that production per well remains constant and that producers drill more wells. It demonstrates an imbalance (potentially met with LNG) of approximately 3 Tcf by 2017.

The low supply case assumes production per well falls off, that the number of wells drilled is capped at the 2006 approximate number of 30,000, and that Canadian supply falls off somewhat more quickly. In this case, the imbalance (potentially met with LNG) grows to nearly 10 Tcf by 2017.

R. W. Beck also evaluated the relationship between oil and natural gas prices. This is a perennial debate. Many assume that natural gas prices should trade at a fixed ratio to oil prices. The analysis demonstrates that the relationship between oil and natural gas prices is much more complex and varied.

Forecast Methodology

As its principal tool to assess natural gas market fundamentals, the Energy Commission staff uses the World Gas Trade Model, which includes the NARG model as its North American component This model uses a fundamental approach in which market-clearing prices and quantities are determined at the point of supply-demand equilibrium. The model uses as its input a number of variables generally categorized in terms of regional supply curves for North American natural gas: costs of existing and prospective field processing and gathering; costs of existing and prospective long haul and backbone pipelines; demand and the price, income, and weather sensitivity thereof; LNG liquefaction, shipping, and re-gasification worldwide; and full arbitrage of tankers and gas through the continent and around the world. Fundamental models have proven very useful and quite accurate for simulating production, product flows, and consumption and to superimpose and consider non-economic uncertainties such as the impact of transportation limitations and costs on locational price differentials.

However, there have been concerns with regard to prices projected by NARG and similar models as they tend to deviate from actual market prices. The following observations briefly explain the issue.

Fundamental models like NARG are designed to estimate equilibrium—that is, the point at which supply balances with demand. The marginal cost of supply at the equilibrium point becomes the forecast price of natural gas. Therefore, the price such models project is a proxy of the long-term equilibrium marginal cost, which is the development and operation cost of the marginal unit of gas produced.

Although economists generally agree that the natural gas market is highly competitive and liquid, there is tremendous uncertainty about the appropriate values to assign most of the key fundamental and structural variables. The deviations of fundamental model-based projected prices from observed market prices are the result of the difficulties (or the lack) of modeling market uncertainties. Some of the main reasons for the price projection deviations include the difficulty (or the omission) of modeling abrupt and sometimes severe changes in weather conditions, pipelines outages and congestion, production and storage capacity and availability limitations, and the asymmetry of information.

In addition to supply and demand uncertainties, other variables that contribute to the uncertainty of market price movements may include trading behavior, erratic weather events, regulatory and policy shifts, and major outages to supply/infrastructure facilities. Some of these variables can be highly volatile and can sometimes lead to extreme price spikes, which are often short-term in nature and would never be reflected in a model output that yields annual average prices.

In recent IEPR cycles, the NARG model has been used at the Energy Commission deterministically to project annual prices in a base, or reference, case. Sensitivity analyses, which test a limited number of variations of selected variables, are not enough to capture the wide range of possible outcomes.

R. W. Beck prefers a stochastic forecasting approach which explicitly recognizes uncertainty as best able to capture uncertainties associated with key variables, which in turn create a tractable probability density function of future market prices. Such a model is unfortunately not readily available. NARG, however, is used by many subscribers to perform probabilistic analysis and, if it were used in that fashion by the Energy Commission, could theoretically provide a more complete analysis of uncertain variables to the Energy Commission.

Model outputs are also often criticized for being lower than New York Mercantile Exchange (NYMEX) prices. Forward natural gas contracts have traded consistently in the last few years at a premium relative to spot prices. Over the 12 months (January to December) of 2006, NYMEX Henry Hub (HH) monthly forward prices consistently traded at a premium when compared to the actual contemporaneous spot prices of the same 12 months.

Forward contracts account for future market risk and future supply-demand uncertainty but spot prices do not; accordingly, forward prices are not good predictors of spot prices. Comparisons of predicted spot prices to NYMEX thus need to recognize the expected and appropriate difference between the two. Only with this recognition should forward prices be used to benchmark the short-term direction of expected spot market price movement.

It should be noted that R. W. Beck has not “validated” staff’s forecast, per se. Rather, R. W. Beck has worked with staff in analyzing the outputs and benchmarked them to other available forecasts, including both EIA’s most recent Annual Energy Outlook and the forecast produced by Global Energy Decisions for the Energy Commission’s Electricity Scenarios project. As will be later seen, the benchmark comparison shows staff’s reference case to be consistent with those forecasts, other than in the first several years.

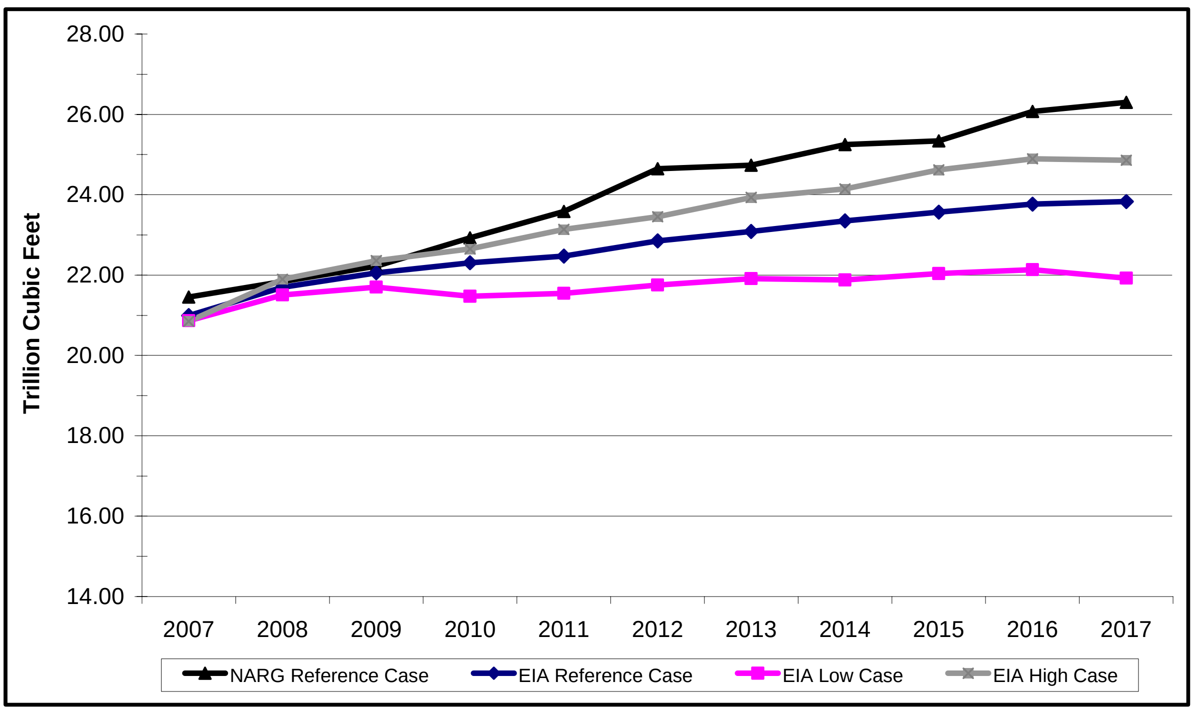
There are also a number of data elements or model elements that deserve further exploration. Staff tends to exclude field use and losses from natural gas demand. This makes comparisons to total supply difficult and sometimes confusing. The model may also have assumed that all resources in the Rocky Mountains are available with no land access restrictions, which may lead to overstating Rocky Mountain production. It is also not well understood whether the model’s insensitivity to higher oil prices recognizes the potential second order effects of higher oil prices on countries exporting LNG, nor has staff had the opportunity to thoroughly understand in what countries’ higher oil prices might lead to substitution away from oil to natural gas. Last, the reference case projects importation of large quantities of LNG. It does not, however, offer much detail describing the underlying LNG cost assumptions. Moreover, the assumptions as to which terminals will be built may be too liberal.

In all, the 2007 Natural Gas Assessment takes a step toward an analysis that can capture more of the intrinsic uncertainty surrounding key variables by combining the deterministic NARG modeling effort with a greater focus on trying to highlight and understand the uncertainties that could cause reality to turn out differently than reflected in staff's NARG reference case.

Demand

R. W. Beck offers two approaches to help the Energy Commission consider the range of potential variation in natural gas demand around staff's reference case. The first uses the variation in historical demand growth to create a statistical range of potential demand. The second lists the factors one might evaluate in a "bottoms-up" approach or that could be incorporated into further scenario or uncertainty analyses. R. W. Beck also "benchmarks" staff's NARG demand forecast against EIA, to illustrate the difference in range of opinion about natural gas demand. The end result is that it appears reasonable to expect that actual demand could deviate above or below forecast demand by as much as 1.5 to 2.0 Tcf per year—a wide range.

Figure 31: Comparison of U.S. Natural Gas Demand Forecasts

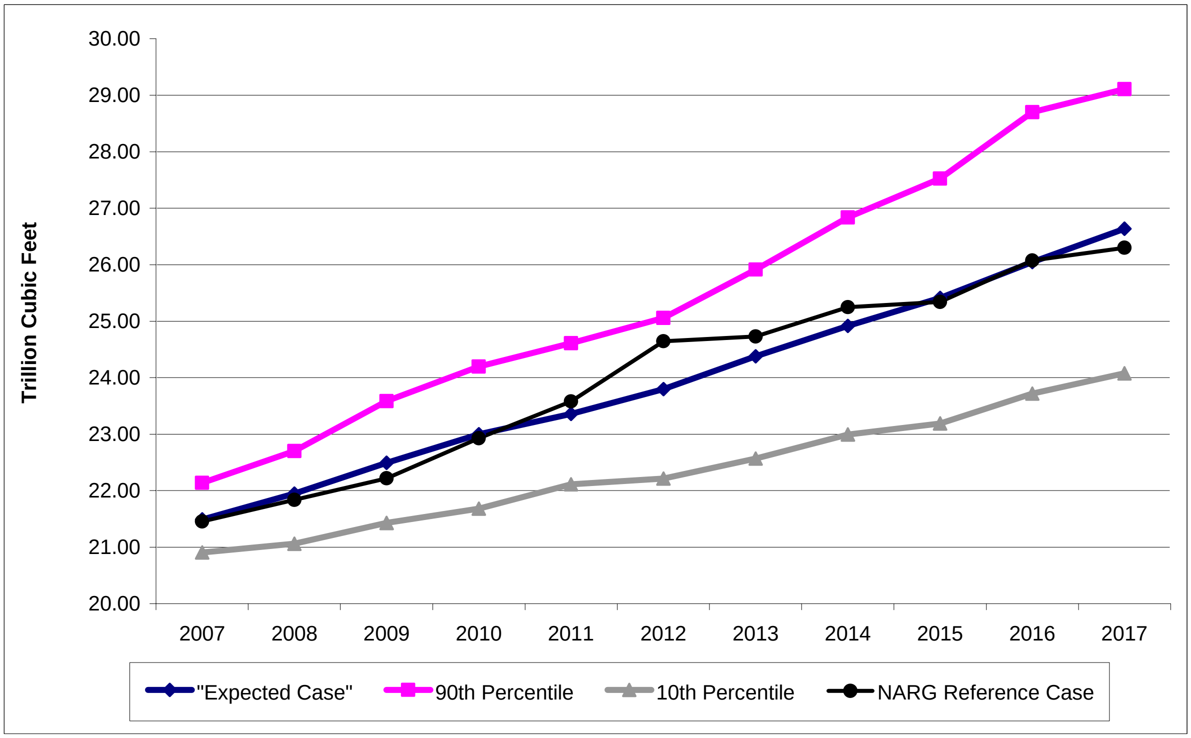


Source: R. W. Beck, 2007

Figure 31 compares the end-use natural gas demand forecast from staff's NARG reference case to the demand cases from EIA's Annual Energy Outlook. The EIA demand is adjusted to remove pipeline, field, and fuel use in order to properly compare it with staff's forecast. Projected demand from the NARG case is very similar to EIA's "high case" in the first half of the forecast period, then rises to become approximately 0.5 Tcf higher than the high case and 2.0 Tcf higher than the reference case in the second half of the forecast period. Generally, EIA's reference case increases at 1.28 percent per year; staff's NARG reference case demand reflects an annual average growth rate of 1.9 percent. One reason for this difference is likely EIA's inclusion of more coal-fired generation in the Western Electric Coordinating Council (WECC) than in staff's NARG forecast, which instead reflects the projected electricity generation mix and dispatch results from the Energy Commission's Electricity Analysis Office. Another difference may be associated with Staff's use of elasticities that allow NARG to adjust some demand in response to price changes.

R. W. Beck used two well-recognized approaches to investigate alternative future demand growth possibilities. The first was to analyze the historical volatility of demand growth for each of the major consuming sectors. The assumptions were that the random and diverse impacts of changes in economic, policy, and market variables are typically imprinted in the statistical distribution of the historical data. Assuming that the statistical distribution of each sector's historical demand growth can be represented by a normal distribution, the estimated historical standard deviation (volatility) and mean (average) of these distributions give a proxy picture to the volatility of future growth. This approach is useful because it allows analysts to focus not on quantifying impacts from specific changes in assumptions, but rather to use the historical volatility of demand growth to capture at once a number of different potential outcomes.

Figure 32: U.S. Demand - Alternative Case Forecasts



Source: R. W. Beck, 2007

After estimating the mean and standard deviation of demand growth for each demand sector, a Monte Carlo simulation approach with 100 random draws was used to estimate the expected value (calculated as the average of the result of the 100 draws) of the rate of growth in demand as well as the 10th percentile and the 90th percentile of future demand growth rates. The 10th and 90th percentiles present an 80 percent confidence level of the range around the expected average of the rate of growth in demand. Applying the expected growth rate to staff's NARG reference case demand yields the "expected case" in Figure 32. It varies from the reference case due to the random draws; likewise, the 90th and 10th percentile cases show ups and downs rather than straight-line constants due to the randomness introduced.

Table 6: Variables Creating Demand Forecast Alternative Cases

Drivers	High Gas Demand Growth Case	Low Gas Demand Growth Case	Scope
Efficiency Policy	Slow enactment of legislation/implementation	Aggressive enactment and implementation of policies	National
Conservation Policy	Slow enactment of legislation/implementation	Aggressive enactment and implementation of policies	National
Carbon-reduction Legislation	Aggressive enactment and implementation of policies	Slow enactment of legislation/implementation	National
Coal Generation	No or little capacity additions	50 % share of new capacity additions	WECC
Nuclear	Business as usual	Progress in licensing proposed plants	National
Renewable	Slow enactment of legislation/implementation	Aggressive enactment and implementation of policies	National
Economic Growth	High growth case	Slow growth case	National
Hydro Condition	Dry hydro condition	Wet hydro condition	WECC California
Electric Transmission	Critical regional paths are congested	Major transmission capacity expansions into California	California

Source: R. W. Beck, 2007

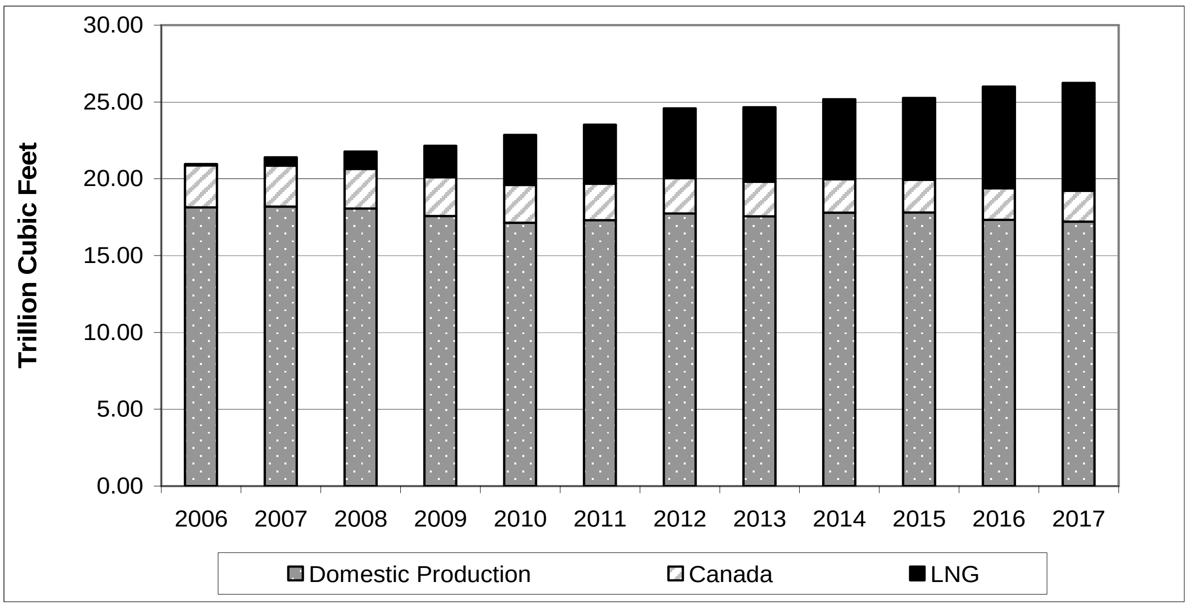
The second approach was to qualitatively build the projected high and low demand growth cases assuming the most divergent assumptions about economic, policy, and market fundamental variables. Table 6 identifies a set of key variables and alternative values those variables could take on to create high and low cases. A complete “bottoms-up” analysis of these variables is beyond what is achievable during the short duration of R. W. Beck’s assignment. Based on the statistical analysis reported above, however, 1.5–2.0 Tcf above and below the expected total demand should represent a reasonable range for high and low demand cases.

Supply

To put the supply view contained in the NARG 2007 reference case in perspective and to develop alternative views, R. W. Beck again compared staff’s projections with other forecasts. Beck then developed a simple heuristic device to provide a “snapshot” of how changes in a few key component variables create very different supply pictures. Beck illustrates a set of assumptions that replicate staff’s NARG reference case for supply and show how possible changes to those assumptions create different supply views.

The difference between supply and demand becomes a “gap,” which policy makers can view as necessary to meet in one of three ways: import LNG, increase domestic production, or reduce demand. The high supply case turns out to be very similar to EIA and leaves an approximately 3-Tcf “gap” between domestic supply and demand by 2017; the low case leaves an approximately 10-Tcf “gap” between domestic supply and demand by 2017.

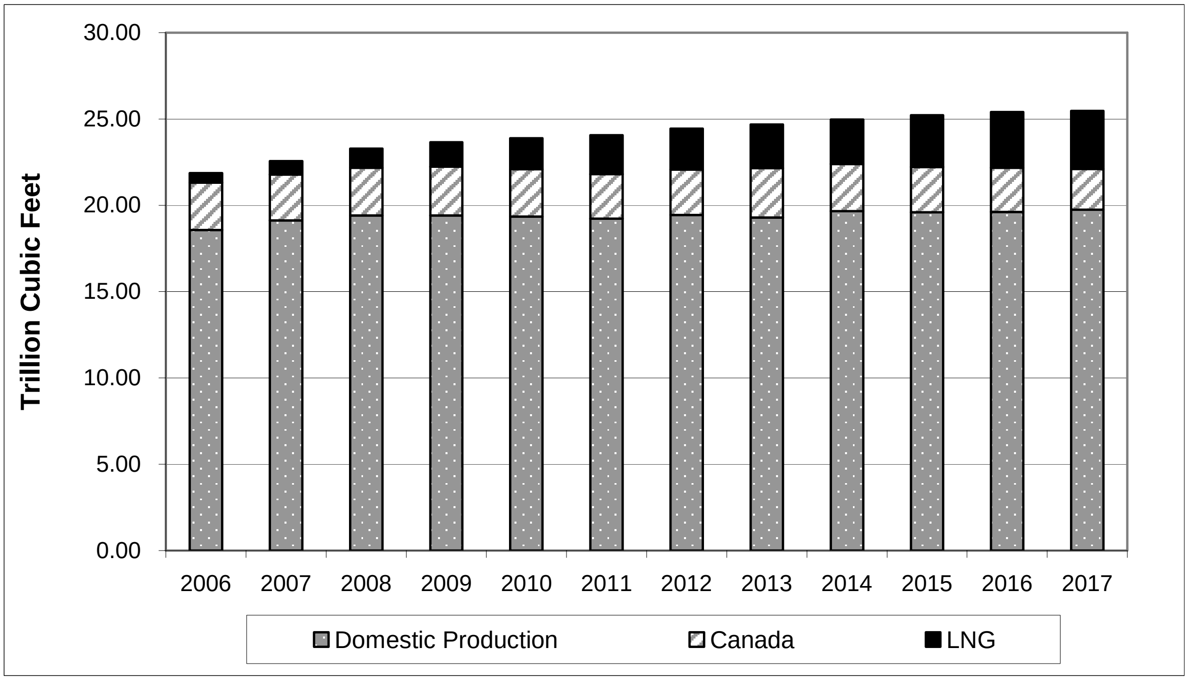
Figure 33: NARG Reference Case - U.S. Natural Gas Supply



Source: R. W. Beck, 2007

Figure 33 displays the key components of U.S. natural gas supply from the reference case.

Figure 34: EIA AEO Reference Case – U.S. Natural Gas Supply



Source: R. W. Beck, 2007

Figure 34 displays those components from EIA's Annual Energy Outlook reference case.

Staff's NARG reference case shows lower U.S. domestic production than the reference case in EIA's Annual Energy Outlook, leaving more demand to be met by LNG.

Why might U.S. gas supply be lower or higher than estimated in staff's NARG reference case? Reasons include:

- Uncertainty over production costs and the ability to produce more from a "declining" resource base.
- Uncertainty over investment patterns and technological development.
- Uncertainty over Canadian production and the volume available for the U.S. to import: declines plus use for tar sands production reduce exports to the U.S. versus relatively stable production.
- Uncertainty over LNG availability, cost, access, and the global supply/demand balance.

Production Cost Uncertainty and Declining Resource Base

The NARG 2007 reference case removed 32 Tcf of probable reserves to recognize "tighter" supply, but the overall curve is still very similar to the 2005 curve. Other data provide strong evidence of increasing production costs.

Table 7: Average North American Gas Cost Structure (Weighted Average)

	2002	2003	2004	2005	2006	2007E
Operating Expense	0.53	0.68	0.78	0.92	1.03	1.15
Production & Mineral Tax	0.12	0.17	0.23	0.29	0.31	0.33
Transportation	1.07	1.19	1.06	1.27	1.24	1.24
General & Administrative	0.12	0.15	0.15	0.19	0.25	0.28
Cash Costs	1.84	2.19	2.21	2.67	2.84	3.01
Finding & Development (incl. Future Capital)	1.77	1.93	2.15	2.70	4.23	4.87
Total Supply Cost US$/Mcf	3.61	4.12	4.37	5.36	7.06	7.88
Percent Change		14%	6%	23%	32%	12%

Source: Tristone Capital, E=estimated

Tristone Capital provided Energy Commission staff with its analysis based on the financial statements of approximately eight of the large independent gas exploration and production companies (Apache, Devon, EOG, EnCana, and others). Note that average finding and development costs from 2002 to 2007 (see Table 7) more than doubled for the sample set of companies.

Table 8: API Joint Association Survey on Drilling Costs - Total United States (Footage in feet, Costs in thousands of dollars)

Depth Interval	2001			2003			2005		
	No. Of Wells	Avg. Depth	Avg. Cost, $	No. Of Wells	Avg. Depth	Avg. Cost, $	No. Of Wells	Avg. Depth	Avg. Cost, $
0 – 1,249	4,658	797	87	2,466	860	131	2,534	862	201
1,250 - 2,499	2,999	1,748	179	2,730	1,793	193	4,387	1,791	268
2,500 - 3,749	1,993	3,182	230	2,336	3,179	263	2,994	3,139	351
3,750 - 4,999	1,652	4,279	307	1,838	4,335	315	2,207	4,329	445
5,000 - 7,499	3,002	6,218	557	2,853	6,319	611	3,159	6,206	911
7,500 - 9,999	2,747	8,582	1,115	3,277	8,561	1,140	3,457	8,715	1,867
10,000 - 12,499	1,810	11,095	1,872	1,814	11,144	2,325	2,388	11,052	3,234
12,500 - 14,999	960	13,422	3,125	1,053	13,366	3,250	1,254	13,488	5,246
15,000 - 17,499	248	15,981	6,075	244	16,023	6,734	293	15,995	8,498
17,500 - 19,999	100	18,440	8,245	80	18,543	12,808	94	18,315	15,793
20,000 +	17	21,474	16,014	23	21,368	16,038	21	20,906	20,605
Total	20,186	5,140	775	18,714	5,807	972	22,788	5,656	1,394

Note: Gas Wells Only; Source: Lippman Consulting Inc.

The American Petroleum Institute (API) drilling costs (see Table 8) show a similar result. API shows that the average cost of all wells drilled has increased by 80 percent since 2001. Costs have increased at each depth interval. Note the very large increase in the cost of wells at 10,000 to 12,499 feet and 17,500 to 19,999 feet.

Uncertainty over Investment Patterns and Technological Development

Production per new well has declined dramatically over the last eight years. It is not clear whether this is due to drilling smaller fields into production or whether it is the inevitable result of new technology that allows the harvest of unconventional resources that by their nature produce less per well. Such wells may be more costly, but present lower risk to producers than new exploration. Thus, those who claim the U.S. cannot produce more natural gas confuse cause with effect and misunderstand the economic drivers that push producers to focus on a quick return infill drilling.

Table 9: Change in Production per New Well Drilled

Year	Production per New Well		Wells Required in Order to Produce 2.5 Tcf
	Bcf	MMcfd	
1999	0.162	0.444	15,427
2000	0.132	0.361	18,981
2001	0.123	0.338	20,252
2002	0.124	0.339	20,222
2003	0.114	0.313	21,917
2004	0.110	0.301	22,725
2005	0.096	0.262	26,107
2006	0.091	0.250	27,414
Annual Rate	-7.5%		

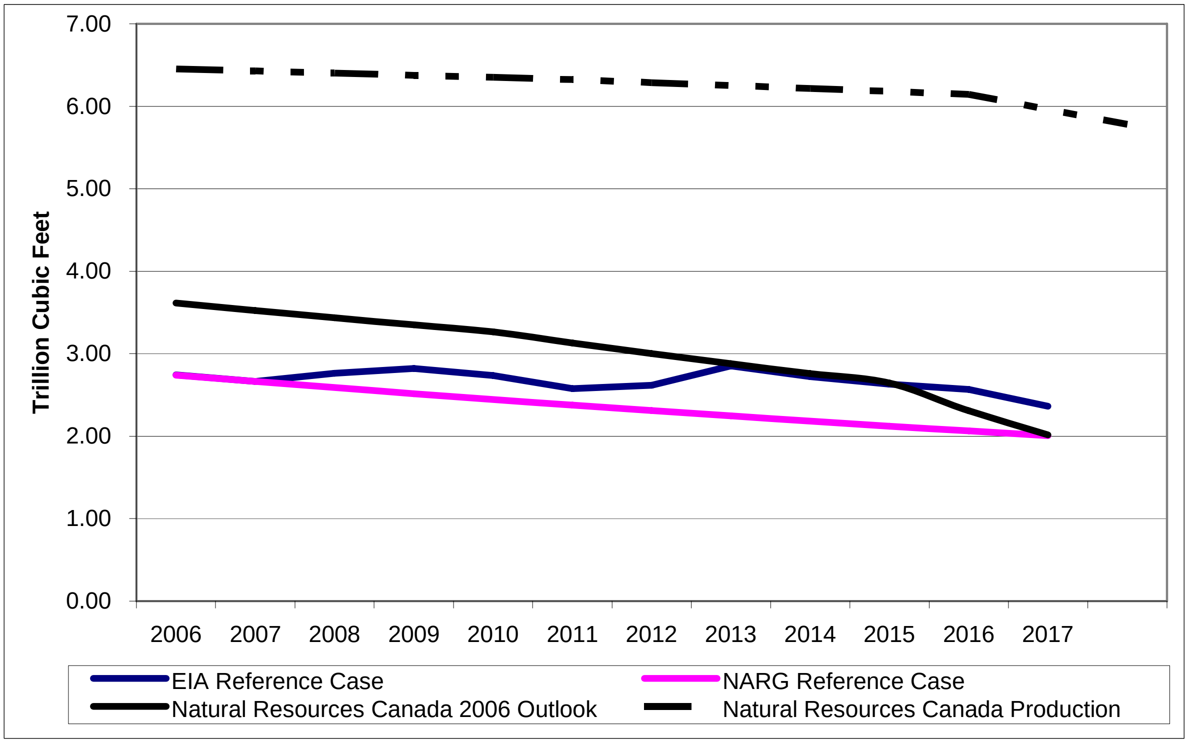
Source: Lippman Consulting, Inc.

As shown in Table 9, further declines in production per new well drastically increase the number of wells that are required to offset depletion.

Uncertainty over Canadian Production and the Amount Available for Import to the U.S.

Uncertainty over Canadian production and the volume that will be available for the U.S. to import is another reason why U.S. gas supply may be lower or higher than staff estimated in its NARG reference case. Declines in production plus use for tar sands production reduce exports to U.S.

Figure 35: Forecasts of Natural Gas Exports from Canada to U.S.



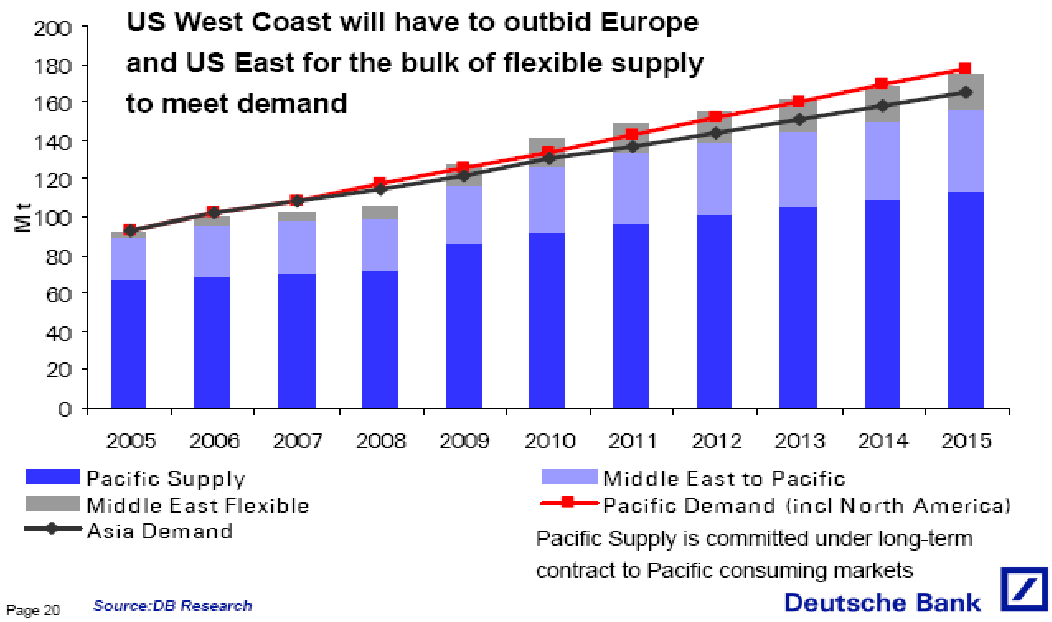
Source: R. W. Beck, 2007

Natural Resources Canada projected in its 2006 Outlook that its natural gas production would decline by about 0.7 Tcf by 2017. Exports would decline by more, owing to greater use of natural gas to process tar sands oil. In Figure 35, staff's NARG reference case shows Canadian supply available to the U.S. declining by about 2.5 percent per year; EIA's Annual Energy Outlook reference case shows a smaller decline of about 1.2 percent.

Uncertainty of Multiple LNG Factors

Uncertainty over LNG availability, cost, and access and the global supply/demand balance could also account for variance between actual U.S. gas supply and that estimated in staff's NARG reference case. For example, there is considerable disagreement over the volume of LNG that will find its way to the U.S. and the price it will take to attract it. Economists expect that LNG will trade at the prevailing U.S. market-clearing price as long as it is infra-marginal supply; if it becomes marginal it will set the market-clearing price. But what price will it take to give LNG suppliers sufficient netback to make the U.S. an attractive market relative to other global markets? This question is more acute for foreign LNG production than domestic production because foreign production has more variables and more uncertainty around those variables.

Figure 36: Deutsche Bank Identifies Potential Pressure on LNG Costs from Demand-Pull Perspective



Source: http://www.energyusa-tpc.com/uploads/newsletter-documents/9V5eVw20070308090232.pdf

NARG allows LNG flows into the U.S. when the sum of expected liquefaction, transportation, and regasification costs are lower than the U.S. market-clearing price of natural gas—that is, when the delivered cost of LNG (excluding netback) is the next economic resource. If LNG costs are "too low," then NARG will sequence "too much" LNG relative to U.S. production. A Deutsche Bank presentation (see Figure 36) points out that the west coast may have to pay more for LNG as its price is bid up. Jensen Associates has prepared an outlook for global LNG trade for the Energy Commission. This study suggests a base case view of world LNG supply of 14.9 Tcf by 2015. By comparison, staff's reference case projects 7 Tcf coming to the U.S. and 9 Tcf coming to North America.

R. W. Beck suggests using a simple heuristic device to help evaluate the NARG reference case supply scenario and create alternative views. The heuristic device makes it possible to test the key variables that contribute to the U.S. supply mix—what it takes to create higher levels of U.S. production or Canadian supply and how that translates to higher or lower levels of LNG imports. The heuristic device also makes it possible to test supply scenarios against higher or lower demand scenarios at a glance.

$\text{Supply}_t = (\text{Domestic Production}_{t-1} - \text{Annual Depletion}_t + \text{New Wells Production}_t) + \text{Pipeline Imports}_t + \text{LNG}_t$

Adding demand to the above equation and rearranging yields:

$Demand_t$ - ($Domestic\ Production_{t-1}$ - $Annual\ Depletion_t$ - $New\ Wells\ Production_t$) - $Pipeline\ Imports_t$ = LNG_t

Table 10 below restates staff's NARG reference case in the form of the heuristic calculation.

Table 10: NARG Reference Case Restated

Tcf	A	B	C	D	E	F	G	H	I	J	K	L
	Last Year Dry Supply	Depletion Rate	Lost Via Depletion	Supply After Depletion	Number of New Wells	Production per New Well	Supply From New Wells	EIA Synthetic	Domestic Production	Canada (less export)	Demand NARG	GAP
Assumptions:		2.0%				-4.00%				-2.80%	Reference	
2006	17.73	-11.6%	-2.06	15.67	29,627	0.0830	2.46	0	18.13	2.74	21.04	0.17
2007	18.13	-11.8%	-2.15	15.99	27,640	0.0797	2.20	0	18.19	2.66	21.45	0.60
2008	18.19	-12.1%	-2.20	15.99	26,917	0.0765	2.06	0	18.05	2.59	21.84	1.20
2009	18.05	-12.3%	-2.22	15.83	23,696	0.0734	1.74	0	17.57	2.52	22.22	2.13
2010	17.57	-12.6%	-2.21	15.36	25,185	0.0705	1.78	0	17.14	2.45	22.93	3.34
2011	17.14	-12.8%	-2.20	14.94	34,923	0.0677	2.36	0	17.31	2.38	23.58	3.90
2012	17.31	-13.1%	-2.26	15.05	41,448	0.0650	2.69	0	17.74	2.31	24.65	4.60
2013	17.74	-13.3%	-2.36	15.38	35,040	0.0624	2.19	0	17.56	2.25	24.73	4.92
2014	17.56	-13.6%	-2.39	15.17	43,562	0.0599	2.61	0	17.78	2.18	25.25	5.28
2015	17.78	-13.9%	-2.47	15.32	43,393	0.0575	2.49	0	17.81	2.12	25.34	5.41
2016	17.81	-14.1%	-2.52	15.29	36,670	0.0552	2.02	0	17.32	2.06	26.07	6.70
2017	17.32	-14.4%	-2.50	14.82	45,212	0.0530	2.40	0	17.21	2.00	26.30	7.08

Source: R. W. Beck, 2007

The depletion rate is calculated from Lippman Consulting data and allowed to increase at 2 percent per year. Column E in Table 10 shows the number of new wells required to meet the NARG reference case domestic production forecast. Production per new well is assumed to decrease at 4 percent per year based on data from Lippman Consulting. Four percent is the rate of decrease from 2000 to 2006. Canadian exports to the U.S. are assumed to decline in proportion to the production decline forecast in the NARG reference case. The gap shown in Column L is demand remaining that must be met by other sources.

Table 11: High Supply Case

Tcf	A	B	C	D	E	F	G	H	I	J	K	L
	Last Year Dry Supply	Depletion Rate	Lost Via Depletion	Supply After Depletion	Number of New Wells	Production per New Well	Supply From New Wells	EIA Synthetic	Domestic Production	Canada (less export)	Demand NARG	GAP
Assumptions:		2.0%								-1.23%	Reference	
2006	18.23	-11.6%	-2.11	16.12	29,627	0.0830	2.46	0.07	18.57	2.74	21.93	0.55
2007	18.57	-11.8%	-2.20	16.38	33,112	0.0830	2.75	0.07	19.12	2.67	22.63	0.77
2008	19.12	-12.1%	-2.31	16.82	31,215	0.0830	2.59	0.07	19.41	2.76	23.35	1.11
2009	19.41	-12.3%	-2.39	17.02	28,793	0.0830	2.39	0.07	19.41	2.82	23.72	1.42
2010	19.41	-12.6%	-2.44	16.97	28,621	0.0830	2.38	0.07	19.35	2.74	23.97	1.81
2011	19.35	-12.8%	-2.48	16.87	28,328	0.0830	2.35	0.07	19.22	2.58	24.13	2.26
2012	19.22	-13.1%	-2.51	16.71	33,015	0.0830	2.74	0.07	19.45	2.62	24.52	2.39
2013	19.45	-13.3%	-2.59	16.86	29,392	0.0830	2.44	0.07	19.30	2.85	24.75	2.53
2014	19.30	-13.6%	-2.62	16.67	35,956	0.0830	2.98	0.07	19.66	2.72	25.04	2.59
2015	19.66	-13.9%	-2.73	16.93	32,097	0.0830	2.66	0.07	19.60	2.63	25.27	2.97
2016	19.60	-14.1%	-2.77	16.83	33,479	0.0830	2.78	0.07	19.61	2.57	25.48	3.23
2017	19.61	-14.4%	-2.83	16.78	35,717	0.0830	2.96	0.07	19.74	2.36	25.55	3.37

Source: R. W. Beck, 2007

The high supply case (Table 11) illustrates assumptions that mimic the EIA AEO reference case. Depletion is again set at 11.6 percent and falls at 2 percent per year. The high supply case keeps production per well constant at 0.083 Bcf per new well. The number of new wells in Column E then rises and falls to produce the supply forecast in EIA's AEO reference case, shown in Column I. Canadian supply decreases at 1.23 percent per year, again consistent with the assumption used in EIA's AEO Reference Case. This is a reasonable high supply case because a more optimistic view on production per well increases supply to 19.7 Tcf by 2017, compared with the NARG reference case of 17.21 Tcf. The gap between supply and demand left to be met by LNG is shown in Column L and is substantially smaller than in the NARG reference case.

Table 12: Low Supply Case

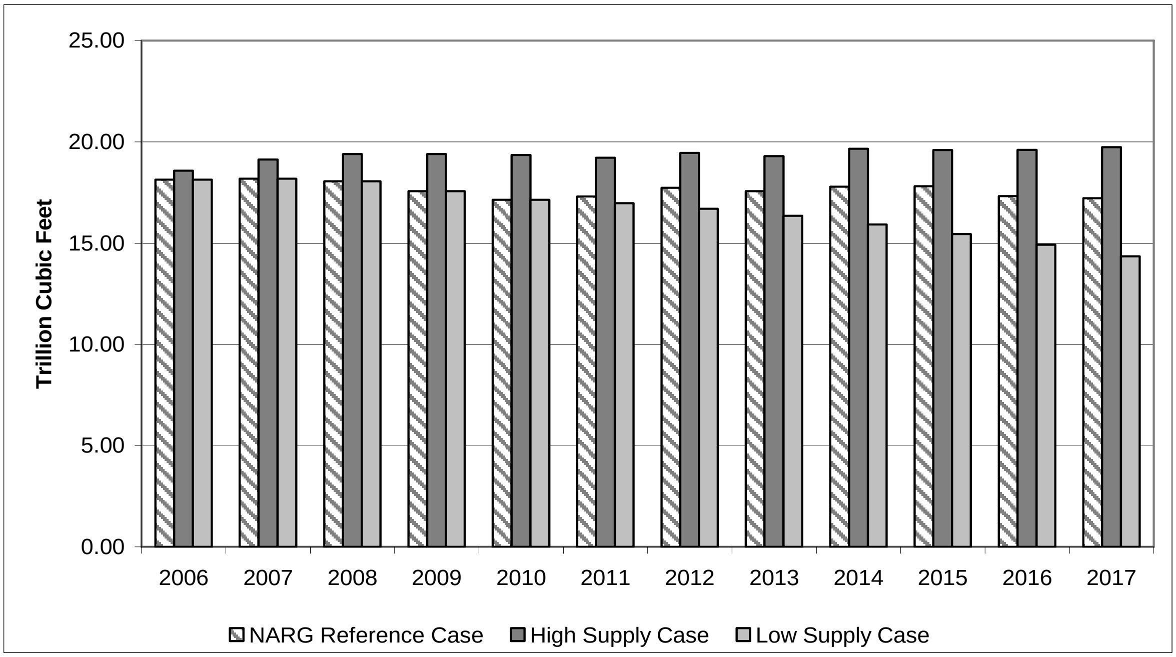
Tcf	A	B	C	D	E	F	G	H	I	J	K	L
	Last Year Dry Supply	Depletion Rate	Lost Via Depletion	Supply After Depletion	Number of New Wells	Production per New Well	Supply From New Wells	EIA Synthetic	Domestic Production	Canada (less export)	Demand NARG	GAP
Assumptions:		2.0%				-4.00%				-2.80%	Reference	
2006	17.73	-11.6%	-2.06	15.67	29,627	0.0830	2.46	0.00	18.13	2.74	21.04	0.17
2007	18.13	-11.8%	-2.15	15.99	27,640	0.0797	2.20	0.00	18.19	2.66	21.45	0.60
2008	18.19	-12.1%	-2.20	15.99	26,917	0.0765	2.06	0.00	18.05	2.59	21.84	1.20
2009	18.05	-12.3%	-2.22	15.83	23,696	0.0734	1.74	0.00	17.57	2.52	22.22	2.13
2010	17.57	-12.6%	-2.21	15.36	25,185	0.0705	1.78	0.07	17.14	2.45	22.93	3.27
2011	17.14	-12.8%	-2.20	14.94	30,000	0.0677	2.03	0.00	16.98	2.38	23.58	4.23
2012	16.98	-13.1%	-2.22	14.76	30,000	0.0650	1.95	0.00	16.71	2.31	24.65	5.63
2013	16.71	-13.3%	-2.23	14.48	30,000	0.0624	1.87	0.00	16.35	2.25	24.73	6.13
2014	16.35	-13.6%	-2.22	14.13	30,000	0.0599	1.80	0.00	15.93	2.18	25.25	7.14
2015	15.93	-13.9%	-2.21	13.72	30,000	0.0575	1.72	0.00	15.44	2.12	25.34	7.78
2016	15.44	-14.1%	-2.18	13.26	30,000	0.0552	1.66	0.00	14.91	2.06	26.07	9.10
2017	14.91	-14.4%	-2.15	12.76	30,000	0.0530	1.59	0.00	14.35	2.00	26.30	9.95

Source: R. W. Beck, 2007

The low supply case (Table 12) goes back to the NARG reference case assumption of a 4 percent decline in production per well. To create the lower supply, staff modified the number of wells to keep them constant at 30,000 wells per year, beginning in 2011. This supposes, essentially, that drilling cannot increase either due to lack of rigs, investment, or labor to drill beyond that amount: 30,000 wells is about the number drilled in 2006. Alternatively, the number of wells drilled could be allowed to increase and production per well allowed to decline by a larger annual percentage to achieve the same result. The low supply case retains the assumption that Canadian supply declines by 2 percent per year.

Each case used this assumption. All else being equal, if U.S. supply is constrained and the Canadian supply declines more than assumed, then the gap met by LNG would increase; the converse is also true. Further, note that the display of the supply/demand balance in this fashion enables one to “eyeball” the result should the supply assumptions hold true but demand change.

Figure 37: Domestic Gas Production in Three Supply Cases



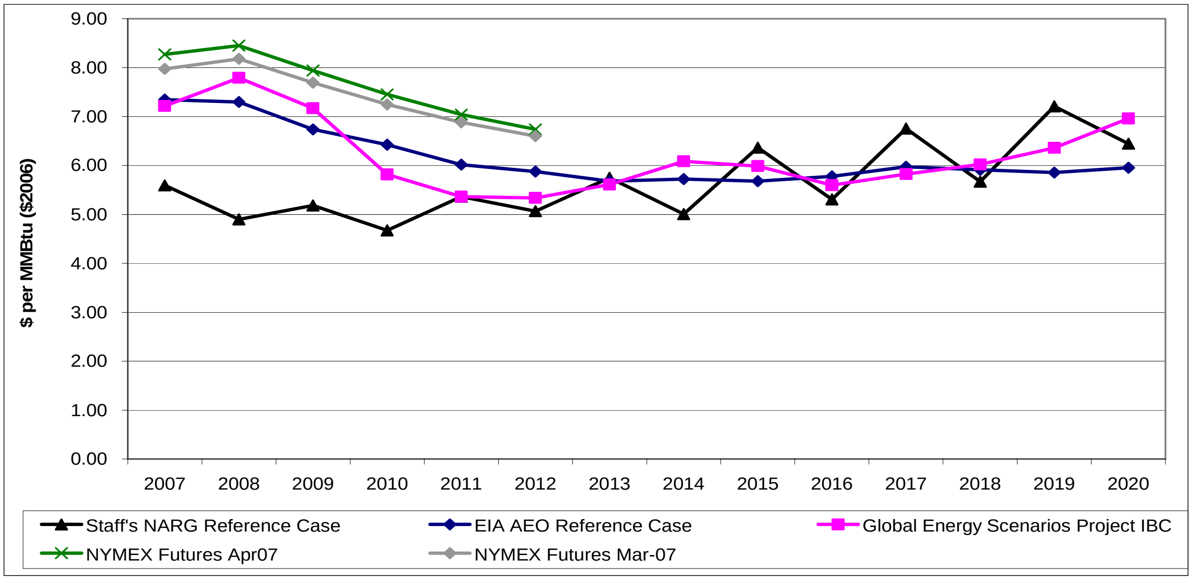
Source: R. W. Beck, 2007

Figure 37 compares the U.S. domestic production calculated in each of the three cases. The three cases project U.S. production in the range of 18 Tcf in 2006. The NARG reference case meanders generally downward, settling at about 17 Tcf by 2017. The high supply case grows production slightly and relatively consistently each year, settling just under 20 Tcf by 2017. The low supply case moves consistently downward each year, with production falling to just over 14 Tcf by 2017.

Price

R. W. Beck did not generate an alternate forecast of natural gas prices, but simply benchmarked staff's reference case to other forecasts. The comparisons show that, particularly in the second half of the forecast period, staff's reference case is similar to other publicly available forecasts. The key difference between staff and others is in the early years.

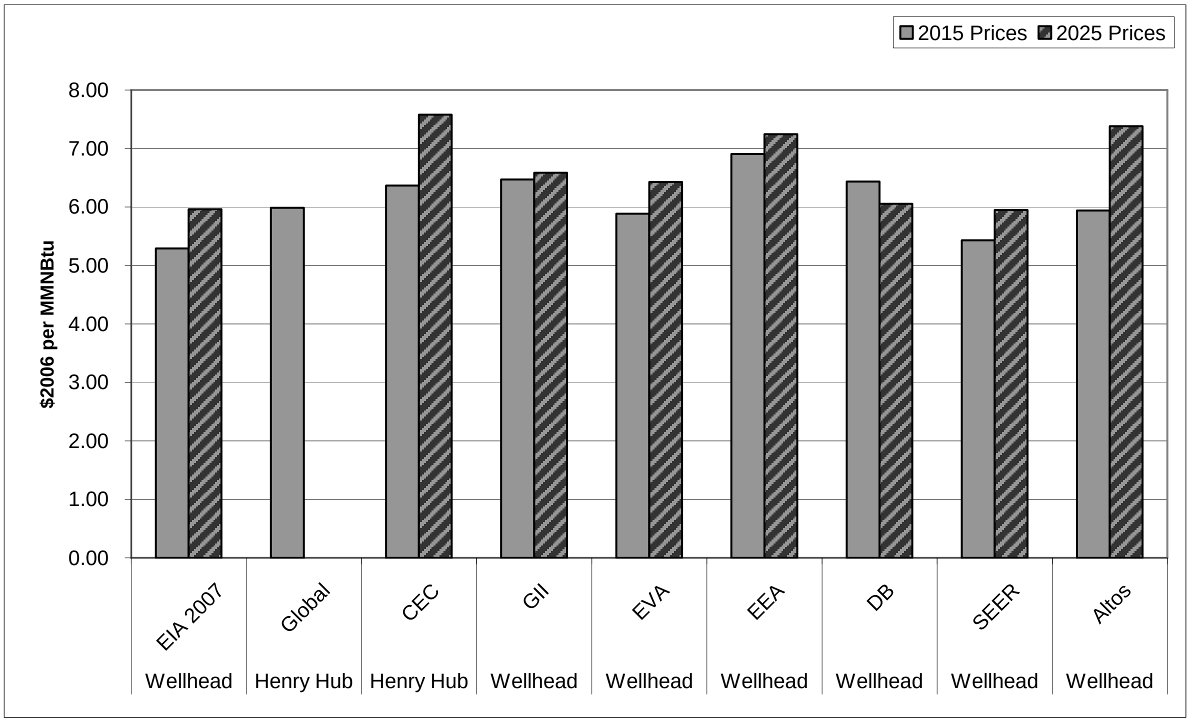
Figure 38: Benchmark of NARG Reference Case to Others



Source: R. W. Beck, 2007

Figure 38 compares staff's NARG reference case with both the EIA Annual Energy Outlook reference case and a case prepared by Global Energy Decisions (Global) for the Energy Commission's Electricity Scenarios Project. Those results will be presented later in the IEPR process. The graph also shows the NYMEX forward contract prices as traded at the end of March and in the middle of April. The figure shows that staff's NARG reference case prices are lower than the EIA and Global prices, as well as the forward prices, during the first four years of the forecast period.

Figure 39: Comparison of NARG Reference Case to Broader Set of Others in 2015 and 2025



Source: R. W. Beck, 2007

The comparison to EIA is made for illustrative purposes because it is publicly available and, as shown in Figure 39, contains references to other forecasts.

The reason for including Global's iterative base case (IBC) forecast is that staff's NARG modeling is not the only work the Energy Commission is doing that involves modeling natural gas prices. The Scenarios Project uses, for certain of its analyses, what is termed the "illustrative base case" or IBC, which is the Global Fall 2006 reference case, adjusted for oil prices from EIA's Annual Energy Outlook. One should note that Global uses NYMEX for the first 24 months of the period and then slowly reverts over the following 24 months to its own fundamental forecast. For NYMEX, it used an average of the closing prices on December 19–21, 2006.

In addition, Global constructed what it terms "P25" and "P75" cases, demonstrating its view of the range of uncertainty in natural gas prices. Global's IBC is not intended necessarily to imply that the IBC prices will occur, but rather, provides a set of assumptions that staff could use to assess prices relative to the IBC as the scenario assumptions change. This approach was also necessary because staff began the Scenarios Project work before it had even begun its NARG reference case work. Staff held a workshop on January 29, 2007, to discuss the Scenarios Project assumptions, including natural gas price.

Other work pertaining to natural gas prices is also underway under the auspices of the Public Interest Energy Research (PIER) project. That work includes some modeling of underground gas storage, its value, and how storage affects the price of natural gas and also includes an effort to build a monthly model of natural gas prices that captures the impact of storage on seasonal prices in California. The PIER results will not be available until very late in the IEPR process.

R. W. Beck also compiled a comparison of staff's reference case forecast to other forecasts shown in EIA's Annual Energy Outlook. The staff reference case is close to the highest in 2015 and higher than all others in 2025.

Based on its work with staff, R. W. Beck has identified two key factors believed to cause staff's NARG reference case to be lower: Global's incorporation of NYMEX forward prices in the early years and several aspects relating to LNG, including the assumed cost components to land LNG, the number of terminals coming on line, and the load factor of delivered gas supply through those terminals. These deserve further scrutiny.

The key insight provided by the reference case (and from the work by Global in the Scenarios Project) is that LNG delivered to the U.S. beats out, on a cost basis, higher-cost elements of North American gas production, which results in keeping prices lower than they would be if no LNG came to North America. This appears to be particularly true in 2008 and 2009, when a great many Gulf Coast LNG terminals come on line and appear to operate at very high load factors.

Table 13: Variables Creating Alternate Price Cases

Drivers	High Price Case	Low Price Case	Scope
Policy Variables			
Efficiency Policy	Slow enactment of legislation/implementation	Aggressive enactment and implementation of policies	National
Conservation Policy	Slow enactment of legislation/implementation	Aggressive enactment and implementation of policies	National
Carbon-reduction Policy	Aggressive enactment and implementation of policies	Slow enactment of legislation/implementation	National
Cost of Carbon Reduction	High cost $/Ton of CO2 reduction (~ above $15)	Low cost $/Ton of CO2 reduction (~ $5 - $15)	National
Demand Variables			
Coal Generation	No or little capacity additions	50 % of new capacity additions	WECC
Nuclear Generation	Business as usual	Progress in licensing proposed plants	National
Renewable Generation	Slow enactment of legislation/implementation + No major breakthrough in technology and costs	Aggressive enactment and implementation of policies + major breakthrough in technology and costs	National
Economic Growth	High growth scenario	Slow growth scenario	National
Supply and Infrastructure Variables			
Electric Transmission	Critical regional paths are congested	Major transmission capacity expansions into California	California
Pipeline Expansion	New pipelines focus on delivery to Midwest or East leaving less gas for West	Pipelines expand with new production to deliver gas to West	WECC California
North American New Gas Production	Flat production growth	Aggressive investment leads to over- production and/or finding new fields	National
LNG Imports	Less than 3 TCF per year by 2017	Large Imports of LNG (>8 TCF per year by 2017) allow reduced drilling	National
LNG Costs	Increasing world-wide construction costs cause spiral in liquefaction, shipping, and regasification costs	LNG cost plus netback makes LNG more economic than North American production	National
Investment Pattern	Continued focus on short-producing wells	Focus on North America and longer-term view	National
Technology	No change or continued decline in production per well	Technology breakthroughs increase production per well	National
New Leases	Status quo	Open new areas to drilling	National

Source: R. W. Beck, 2007

The key market variables that could lead to high and low gas price projections are summarized in Table 13.

Gas market prices are influenced by a web of highly uncertain and interconnected variables. A stochastic forecasting approach that accounts for the randomness of these variables would provide the means to capture the probability distribution of future market prices. Considering the current deterministic approach employed by the Energy Commission, a multitude of carefully selected sensitivity cases evaluated using NARG would be necessary to provide a reasonable substitute for a stochastic approach. These sensitivity cases need to present a rational picture to some of the expected future scenarios for the natural gas industry and the economy.

Relationship Between Oil and Natural Gas Prices

The NARG model staff used to prepare its reference case includes oil prices as an input assumption. Earlier in this assessment, staff presented the results of two sensitivity cases using high and oil prices in order to understand what impact higher versus lower oil prices might have on projected natural gas prices. R. W. Beck was asked to provide some background and analysis on the general relationship between oil and natural gas prices.

Interestingly, nearly everyone has an opinion on whether oil prices matter in forecasting natural gas prices. Just as interestingly, there remains more debate than consensus about the relationship between oil and natural gas prices and the nature of that relationship. Aside from the historical statistical relation between oil and gas prices, oil prices have an impact on overall economic activities such as consumption behavior, productivity, profitability, and investment. Therefore, a review of the impact and relationship of oil prices to the overall economy is in order first.

Effects of Higher Oil Prices

Higher oil prices affect economic activity in many different ways. The following observations briefly review some common thoughts about the impacts of high oil prices:

- Higher oil prices reduce the spending capacity of consumers and cause a reduction in demand for all of their spending categories.

- Rising oil costs reduce profit margins for companies when they are not able to pass these costs on to their customers. This is especially true for firms in energy intensive sectors, causing the firms to reduce services or cut production levels.

- Higher oil prices spark fears of a price-wage escalation and cause monetary authorities to tighten credit conditions. This, in turn, weakens investment spending, housing, and sales of durable goods like automobiles.

- Higher oil prices hurt both consumer and investor confidence. As equity prices decline, household wealth declines and the economy is weakened.

- The U.S. economy is in a better position now to weather oil price shocks than it was in the past because it is less oil intensive. The U.S. uses half as much oil to produce the same amount of GDP as it did in the 1970s. The rate of decline in oil use relative to the economy, however, has slowed in recent years.

- Oil still plays a significant role in the U.S. and world economies. The U.S. transportation sector relies on oil for 97 percent of total U.S. oil demand. Because the transportation sector remains nearly wholly dependent on oil, consumers cannot quickly reduce consumption in response to higher prices.

Obviously, the extent of these impacts is a function of how high and persistent oil prices are. The cumulative effects of high oil prices on economic activity eventually affect natural gas demand as well as levels of investment and development.

The Observed Relationship between Natural Gas and Oil Prices

For many years, natural gas and refined petroleum were seen as close substitutes in U.S. industry and electric power generation. Industry and electric power generators switched back and forth between natural gas and residual fuel oil, using whichever energy source was less expensive. In the northeast U.S., fuel oil is still often used instead of natural gas to heat homes. Consequently, it has been observed that U.S. natural gas price movements generally tracked those of crude oil. In addition, natural gas was originally viewed as a mere byproduct of producing oil. The exploration and production processes are similar, and the same companies look for and produce both natural gas and oil.

The following observations highlight this relationship:

- Oil and natural gas are competitive substitutes primarily in the electric generation and industrial sectors:

- According to EIA, 18 percent of natural gas usage by manufacturers can be switched to oil products (The EIA *Manufacturing Energy Consumption Survey* [MECS], 2002).

- According to the National Petroleum Council (2003), 20 percent of power generation capacity is dual-fired, but in practice very little capacity switches to oil.

- Additional fuel switching is achievable by generation dispatching, although limited because of environmental constraints.

- High oil prices lead to an increase in oil production. High oil production increases gas production as a co-product (associated gas production in 2005 was about 2.7 TCF, 14 percent of all NG production in the U.S.).

- High oil prices also increase revenues and cash available for oil and gas companies, which lead to higher capital spent on drilling and development of new gas projects.

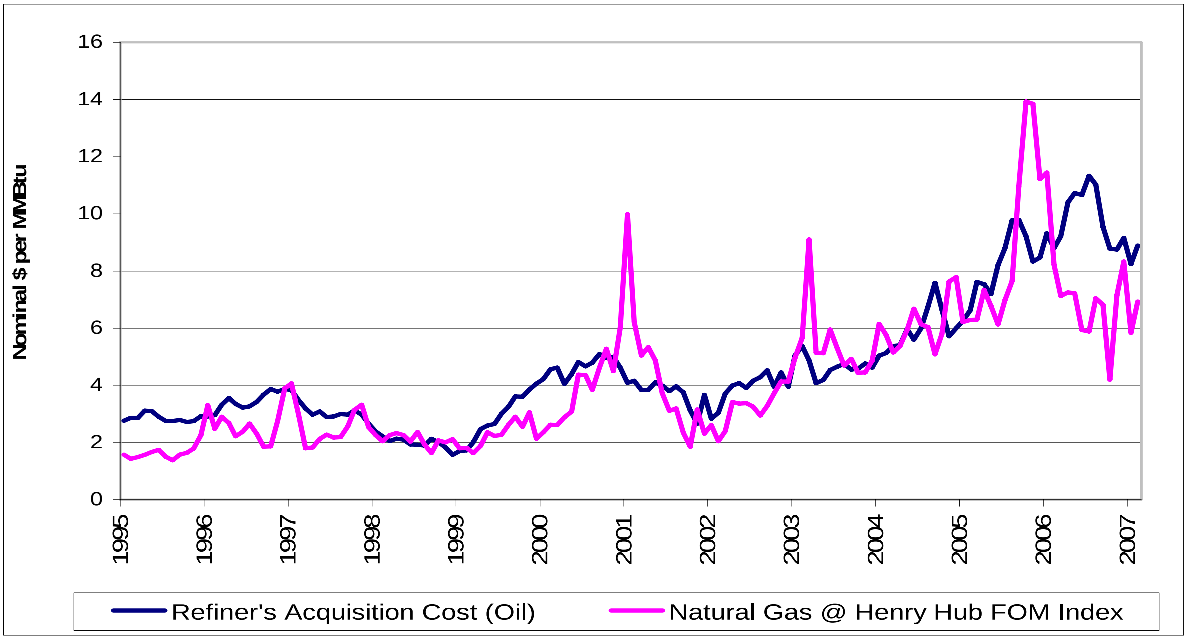
- LNG contracts in the global market were historically indexed to oil prices. Many analysts expect new contracts to use natural gas indices as their pricing mechanism.

Market analysts generally identify weather and seasonal gas storage levels as key drivers of natural gas prices. Using an error-correction model,[5] Brown and Yücel show that when these and other additional factors are taken into account, movements in crude oil prices have a prominent role in shaping natural gas prices. Their findings imply a range of prices at which natural gas and petroleum products are substitutes.

In an affirmation of these observations, Bachmeir and Griffin (2006) find a weak relationship between oil and U.S. natural gas prices. In contrast, a more recent study by Villar and Joutz (2006) find oil and natural gas prices to be co-integrated with a trend. The dynamic relationship they find between the oil and gas prices suggests that a one-month temporary shock to West Texas Intermediate (WTI) of 20 percent has a 5 percent contemporary impact on NG prices, but dissipates to 20 percent in two months. Also, they find that a permanent shock of 20 percent in WTI prices leads to a 16 percent increase in the HH prices one year out, all else being equal. They concluded that oil prices influence the long-run development of natural gas prices, but are not influenced by them.

[5] Stephen P. A. Brown and Mine K. Yücel, Federal Reserve Bank of Dallas , *What Drives Natural Gas Prices?*, February 2007

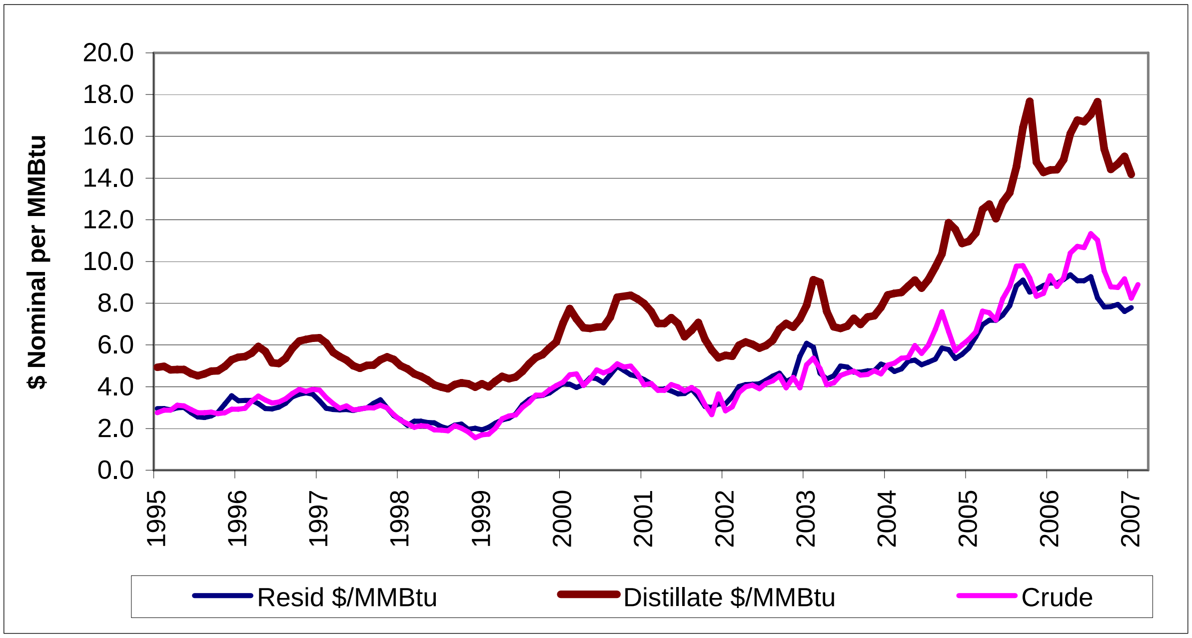
Figure 40: Natural Gas and Equivalent Oil Prices ($ Nominal/MMBtu)



Source: R. W. Beck, 2007

Figures 40 and 41 show the historical movement of gas prices versus the equivalent oil prices in $/MMBtu and the movements of crude, residual, and distillate oil prices. It is noteworthy, as shown in Figure 40, that oil and gas prices do appear to have moved upward on generally parallel paths most of the time from 1995 to 2005. Natural gas prices display large winter spikes that oil prices do not display. Since late 2005, natural gas prices are clearly less linked to oil prices.

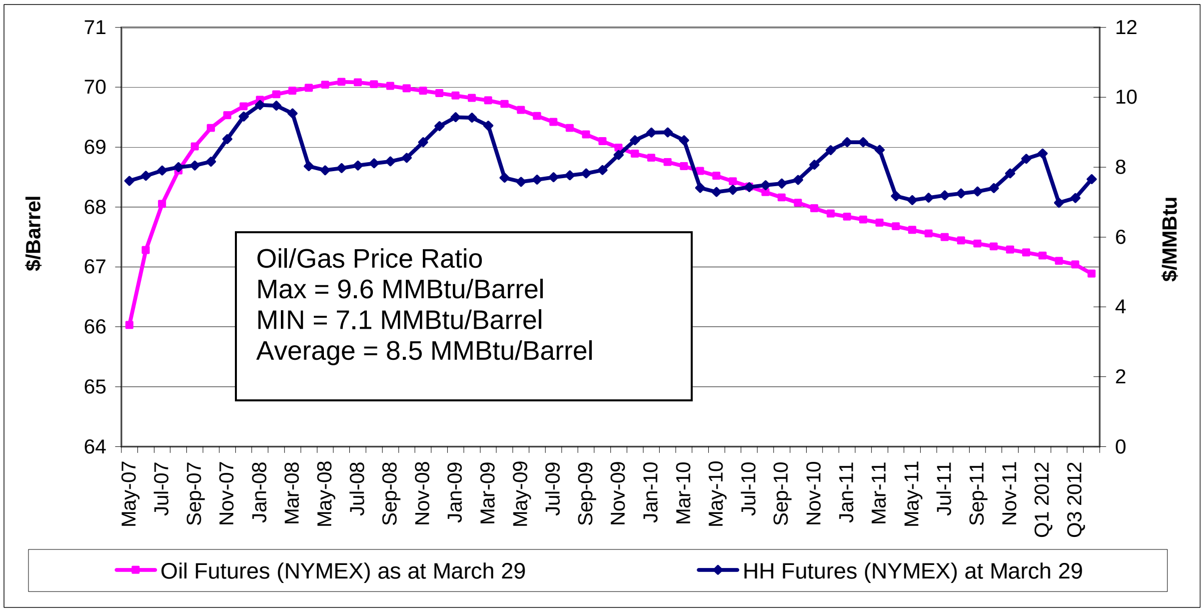
Figure 41: Equivalent Crude Oil, Residual, and Distillate Oil Prices



Source: R. W. Beck, 2007

Figure 41 depicts the historical relationship between crude oil and residual oil prices. Residual oil, which has more (albeit, limited) potential substitutability with natural gas than all other refined petroleum products, is sometimes a price taker during periods in which its prices are slightly decoupled from crude oil and other refined product prices. As should be expected, the more refined distillate trades at a premium to crude, while residual oil trades at prices very close to crude oil. Between 1995 and perhaps as late as 2004, distillate appears to have traded at a relatively constant differential to crude oil; beginning in early 2005, that premium appears to have increased, in relative terms, as demonstrated by a widening gap between the two price streams.

Figure 42: NYMEX Oil and Gas Futures as of March 29, 2007



Source: R. W. Beck, 2007

Figure 42 depicts the oil-to-gas price ratio embodied in NYMEX forward monthly contracts traded on March 29, 2007. The average ratio in MMBtu per barrel is 8.5 with a range of 7.1–9.6. It is important to note that the ratio is not a constant, indicating that the two price streams do not move together.

In summary, based on the reviewed literature and market data observations, the relationship between oil and natural gas prices is complex: there *is* a relationship, but it is difficult to characterize and it is not constant. This finding appears to be somewhat consistent with the sensitivity case results produced by staff's modeling work, which demonstrates an asymmetric effect from changes in oil prices, with higher oil prices having little effect on natural gas prices, while lower oil prices have a much larger one.

APPENDIX A: ELECTRIC GENERATION AND TRANSMISSION INFRASTRUCTURE DEVELOPMENT ASSUMPTIONS 2008-2017

Methodology to Develop Infrastructure Assumptions

Electricity Analysis Office (EAO) staff conducted a 10 year simulation for the forecast period 2008-2017 using Global Energy Decisions (GED) Marketsym model. Changes to the GED dataset included using the Energy Commission Demand Analysis Office (DAO) forecast for California peak demand and annual energy requirements, and the natural gas price forecast developed by the Energy Commission Natural Gas Unit (NGU). The supply-side resource mix included existing resources and high-probability, named resource additions, as well as staff's best estimate of expected generic renewable energy units that may be added. The data used to develop this staff estimate includes the Long term Procurement Plans (LTPP) provided by PG&E, SCE, and SDG&E, and the Resource Adequacy filings provided by SMUD and LADWP, in addition to the discussion of infrastructure challenges included in those filings by the utilities. These renewable units were added to the dataset as an attempt to mimic possible future system conditions given the mandated renewable portfolio standards now in place in many states in the WECC for the purpose of determining natural gas demand for utility electricity generation (UEG.) A more detailed description of what unit types were added and the methodology used to estimate these additions will be presented later in this appendix.

The results of the initial simulation were reviewed to provide an assessment of how well the model simulated actual system operations. The review included a check of simulation results including: energy not served, wholesale market clearing prices, transmission line loadings, and capacity factors for combustion turbines, steam turbines, and combined cycle plants. Hourly, monthly, and yearly simulation results were reviewed over the forecast. Close scrutiny was given to summer peak season results, most notably for system operations in California.

The results of the simulation did not reveal any obvious "red flags" or highly unusual predictions of system conditions. Near term results that were observed could be considered plausible under "normal" conditions in the WECC (for example: market clearing prices were not extremely high or low, capacity factors were consistent with historical operations data). Given that load growth continued throughout the WECC in the forecast period, in years six through ten of the simulation, market clearing prices rose significantly and some areas did experience energy shortages in later years due to "lumpy" resource additions.

System Build-out Generation Resources

Staff chose to begin the system resource build-out with renewable energy technologies due to the many state mandates that now exist throughout the WECC in the form of Renewable Portfolio Standards (RPS). While there are many factors to consider when resources are added to a portfolio, state mandates for renewable energy outweighed other considerations. Staff used inputs to the model that tried to reflect actual system conditions for renewable energy (for example: reduced capacity for wind resources during summer peak, operating profiles for solar resources based on historical data) Staff calculated renewable capacity additions by converting energy (GWh) into capacity (MW) using a simple formula and observed capacity factors for different technology types.

For California, shortfalls in meeting renewable energy targets were addressed by adding renewable generation based on Investor Owned Utility (IOU) public filings, known renewable energy projects, and in-state renewable energy potential. Different assumptions were made regarding annual procurement targets (APTs) and resource procurement for each IOU. For California publicly owned utilities (POUs), it was assumed that 10 percent of load would be served by renewable energy by 2013. A more detailed description of this process will follow later in this appendix.

For other states in the WECC with RPS mandates, staff used each of those states specific legislative mandates to develop annual targets. Some state mandates give preference to specific renewable technologies or provide set asides to require a percentage of renewable energy to be generated from a particular technology. These conditions were addressed by staff in the renewable energy assumptions.

Qualifying RPS generation from the simulation was compared to annual state targets to determine if surpluses or shortfalls existed. Based on the results, generic renewable additions were increased or curtailed so that annual procurement targets were achieved, or nearly achieved.

After adding generic renewable resources to the dataset, staff produced a load-resource balance report at the control area level using the Marketsym model. Using dependable capacity estimates for resources for the peak month for each control area, staff calculated the amount and type of capacity needed to bring control area resources up to a 15 percent (approximate) reserve margin. In some cases the annual reserve fell below this target, but it was assumed that excess capacity in neighboring areas would allow for energy to be imported in order to maintain reliability and prevent excessive wholesale energy prices. Using typical generic resource characterizations, staff added combustion turbines, combined cycle plants, or coal fired steam turbines depending on the types and quantities of resources needed, and the specific control areas in need of capacity.

Existing and Planned Transmission Path Development

Not only is the generation demand and supply infrastructure critical to natural gas demand for electric generation, so is the transmission infrastructure assumed and forecasted to be built. This section describes the method by which the transmission path infrastructure was upgraded in order to satisfy the demand and generation infrastructure upgrades described in the previous sections of this Appendix.

The initial step in evaluating the existing western transmission system under EAO's Basecase was to find historical utilization of the major transmission paths. The year 2008 is considered the base case or benchmark year. Figure A-1 (at the end of this appendix) illustrates the transmission infrastructure reasonably certain to be in available in 2008. Selected actual flows in the Western Interconnection from 1998 through 2003 were compiled for benchmarking purposes. Actual flows were not available for all paths in the WECC, but the flows that were studied provide an indication of how the existing system is used to serve load. This information is also useful in the analysis and identification of potential future areas of congestion and for verifying our modeling representation for production cost analysis. The information can also be used to understand anomalies where transmission scheduling is constrained despite actual flows being less than path transfer capabilities. However, it is not intended to be used to conclude whether there was significant congestion on a path. In addition, it cannot be concluded from this historical analysis that it is either necessary or economical to take any corrective actions for the loading levels reported. For some paths, the real-time Optimal Transfer Capability (OTC) was not reported and assumptions were made based upon WECC published path transfer capabilities. These current assumptions are shown in Table A-1.

This study includes transmission expansion analyses under an average load forecast; average hydro conditions and an average range for natural gas and coal prices. By 2017 this Basecase dataset includes *new generation development capacity* that is 55 percent natural gas-fired, 33 percent renewable, and 11 percent coal from a WECC perspective. For California, by 2017, the *new generation development* contains 59 percent natural gas-fired capacity and 41 percent renewable capacity.

Only major path upgrades that are approved by a regional transmission planning organization with financing were included prior to 2013 in our Basecase. For 2013 and beyond production cost simulations were iteratively run to determine if generation was stranded and/or transmission paths were utilized above 75 percent on an annual basis and/or utilized at 100 percent during the time of a given regions peak. Once paths were identified for possible expansion for 2013 and beyond, staff considered and included some of the transmission projects proposed in utility RPFs, or those proposed by regional transmission planning studies and organizations. The final transmission plan is shown in Figure A-2 (located at the end of this appendix) and includes over 15,000 MWs of transmission path upgrades between 2009 and 2017 in the WECC. See Table A-1 for more details regarding the timing of each of the assumed Path upgrades.

Table A-1: Transmission Path Upgrades 2009-2017

				Transmission Path Expansion (Incremental)			
No.	Trans. Area #1	Trans. Area #2	2008 Path Rating (MW)	Year	Addition #1 (MW)	Year	Addition #2 (MW)
1	BC	AB South	640v	2016	750		
2	South NV	Arizona	4785	2009	1,430		
3	AB South	BC	600v	2009	350	2016	400
4	Northwest	BC	2200v	2009	500		
5	WY West	Idaho	2307	2013	500	2015	200
6	Imperial	IID	120	2013	380		
7	SCE	IID	600	2013	900		
8	Utah	LADWP	1920	2009	480		
9	Northwest	Montana	1390v	2012	310	2014	500
10	BC	Northwest	2650v	2009	500		
11	Montana	Northwest	2200	2011	500	2013	500
12	SCE	Palo Verde	1800	2010	1,200		
13	SF	PG&E	700	2010	800		
14	Arizona	South NV	4867	2009	1,430		
15	IID	SCE	600	2013	900		
16	Palo Verde	SCE	1800	2010	1,200		
17	PG&E	SF	1100	2010	400		
18	AB South	Montana	300	2014	500		
19	Montana	AB South	300	2014	500		

v-indicates that path OTC rating varies seasonally

Simulation Process: Basecase Assumptions for California and Rest of WECC

California Peak and Energy

For this analysis, staff used the 1-in-2 temperature load forecast developed by the Energy Commission Demand Analysis Office (DAO). (http://www.energy.ca.gov/2006publications/CEC-400-2006-008/CEC-400-2006-008-SF.PDF) The forecast includes peak demand in megawatts and yearly energy in gigawatt-hours by transmission area for the years 2008 thru 2017.

This peak and energy forecast, updated in 2006, does not include assumptions about the California Solar Initiative or Energy Efficiency measures beyond 2008. The California Solar Initiative (CSI) was signed into law after our previous forecasting cycle. CSI numbers are incorporated into DAO's upcoming peak and energy forecast. Energy Commission policy is to only include committed (with CPUC approved budgets) energy efficiency programs into DAO's peak and energy forecast. Updated studies on these potential energy efficiency measures will be included in DAO's upcoming peak and energy forecast.

Non-California Peak and Energy

For all areas outside of California, staff used the load forecasts provided by GED. These forecasts were developed by GED using publicly available data from EIA and FERC as well as data provided to GED by utilities. Load forecasts include adjustments for conservation and distributed generation. Local load growth patterns and utility load factors are used in projecting future peak demand and yearly energy consumption for non-California utilities.

Fuel Prices

Natural Gas: Staff used the most recent update to western natural gas prices developed by the Energy Commission Natural Gas Unit. The gas price forecast includes 31 different pricing points for U.S. portion of the WECC (including 13 for California), two for the Canadian provinces and one price point for Northern Baja, Mexico. Gas prices fluctuate monthly for the entire forecast period. CA natural gas prices differ by geography, proximity to the pipeline "backbone", and amount used.

Coal: Coal prices in the WECC are assigned to one of two different basins: the Powder River Basin and Rocky Mountain Basin. Fuel prices for each plant are calculated using one of the basin prices (based on proximity and deliverability) and an associated cost adder, also known as transport costs. Coal prices fluctuate monthly through the end of 2008, but are annual prices from 2009 through the end of the forecast.

Fuel Oil: Fuel oil prices for the WECC were updated by GED in the spring of 2007. Fuel oil prices fluctuate monthly throughout the forecast period.

Uranium: GED updated the price forecast for Uranium 308 in the spring of 2007. The price is for an assumed dollar amount per pound U308, based on a long term supply contract.

WECC Generation Additions-Named and Generic

To supplement the existing resource base, staff made assumptions regarding the addition of new resources in the WECC. These resource additions can be segregated into three different types: high probability named additions, generic renewable additions, and generic thermal additions. These resource types are described below.

High Probability Named Additions

This group of plants includes thermal, hydro, and renewable projects that have moved through the development process and are currently under construction, or have secured the necessary permits, financing, and have a contract for the plant output. This group of plants may also include projects that have been announced by a utility with a projected resource shortage and have chosen to develop the project on their own. These projects are named, have a specific location for the project, and have secured an interconnection point for the facility to connect to the grid.

Staff reviewed the set of high probability additions in the GED dataset (GED: initial entry) and compared it to the new project data from the Energy Commission Siting Office, and new generation database kept by EAO staff. The dataset provided by GED was consistent with data from staff for plant name, unit type, capacity, fuel type, and commercial on-line date, with few exceptions. Some minor edits were made to the data so that it would match Energy Commission data prior to conducting the final simulation.

Table A-2: WECC High Probability Named Additions Capacity (MW) Aggregated by Fuel Type*

Fuel Type	2007	2008	2009	2010	2011	Cumulative Total
Biomass		20	85			105
Coal		357	1,150	184	450	2,141
Geothermal	47	276	120			443
Hydro	30	513		49		592
NG	2,205	3,164	1,532	1,280		8,181
Other	12	80				92
Pump Storage		40				40
Solar	64					64
Wind	1,798	706				2,504
Total	4,156	5,156	2,887	1,513	450	14,161

*Additions are not necessarily for California and SB1368 was not factored in to the capacity additions

Table A2 provides yearly additions by fuel type for this set of new plants. (Note: there are no high probability named additions added to the basecase after year 2011). Please see Table A-3 at the end of this appendix for the complete list of named additions.

WECC Generic Renewable Additions

A review of the IOU 2006 Long Term Procurement Plans (public versions) was conducted to obtain each utilities estimate of current levels of RPS eligible production. In addition, these plans provide an estimate of annual incremental renewable energy (RE production to meet individual IOU targets. Using this data and information regarding RE projects and proposed transmission projects, staff made assumptions for each IOU regarding how they would meet state RPS obligations. DAO load forecasts were used in annual procurement calculations.

Southern CA Edison: Staff used SCE's Best Estimated Plan as a guide to SCE's annual RE procurement. Rather than assume that SCE will reach the 20 percent goal by 2011, staff used a one year lag time for SCE procurement, reaching the 20 percent goal in 2012. This date is consistent with estimates for transmission expansion in the Tehachapi region to allow for increased penetration of wind energy that is deliverable to SCE load.

Pacific Gas & Electric: Using PG&E's Basic Procurement Plan estimates for renewable energy and DAO load forecast, staff developed a RE procurement assumption that assumed an equal percentage of RE procurement each year from 2010 to 2013. While PG&E assumed that it would increase its total renewable percentage from 15 percent in 2009 to 20.2 percent in 2011, they also noted that transmission availability and RE resource availability were key barriers in achieving their 2011 target. For these reasons, staff was more conservative, estimating that PG&E would reach the 20 percent goal in 2013.

San Diego Gas & Electric: Staff used SDG&E Preferred Plan estimates for existing, planned and generic RE for years 2007-2009. Using these estimates, the RE percent climbed from 6 percent in 2007 to 13.8 percent for 2009. Beginning in 2010, staff used lower estimates for RE procurement than did SDG&E. In the 2006 filing, SDG&E states that it has 16.4 percent of RE under contract for 2010. Using the DAO load forecast for 2010, staff calculated the amount of RE for 2010, then used a linear approach to SDG&E obtaining 20 percent of RE by 2013 (as opposed to SDG&E reaching 22 percent by 2010 as the IOU claims). Staff's opinion on this RE trajectory is based on the limited availability of in basin RE, and is consistent with planned transmission expansion projects in Southern California.

For California POUs, it was assumed they would work toward a RPS target of 10 percent by 2013. This estimate is based on staff's review of current level of renewable production from POUs and POU RE projects in development and announced in media reports. While POUs are not required by state law to provide customers with a specific percentage of energy from renewables, larger POUs (LADWP, SMUD) have set their own RE goals. Staff considers the estimate of 10 percent by 2013 to be in line with POU RE projections, if not slightly conservative.

Data obtained from the Energy Commission Renewable Office staff estimated that 6.5 percent of 2006 POU delivered energy came from eligible renewable technologies (4,689 GWh). For staff's basecase, this amount of generation was assumed to continue and additional RE was added by staff in order to meet a 10 percent target by 2013. POU RE projects that are announced and in development were added, along with assumed generic renewable additions.

A spreadsheet database was created to track renewable energy production, individual state renewable energy requirements, and generic renewable additions throughout the forecast period. For those states with RPS requirements, yearly loads (in GWh) for the utilities subject to each states RPS were aggregated. Information on which states have RPS and a summary of the standards was acquired from the Database of State Incentives for Renewables and Efficiency (DSIRE) website. (http://www.dsireusa.org) Annual renewable production was then calculated from the simulation results using eligible technologies for each state, and any multipliers or credits were factored into the total renewable energy production for each state (for example: 1.5 kWh credit for in-state production of 1 kWh produced from solar technology). Yearly renewable targets for each state were compared to yearly production to determine if new renewable resources would need to be added to meet state mandates. In those states where production fell significantly short of the target, generic renewable resources were added to the basecase.

For those states with a RPS requirement in place, EAO staff added renewable energy to the mix of resources for each state, prior to adding generic, non-renewable resources into our basecase.

Out of state RE additions were based on a review of each state's potential for renewable energy technologies, as outlined in the *Renewable Energy Atlas of the West*, published in July, 2002. The atlas was produced and written by the Land and Water Fund of the Rockies, Northwest Sustainable Energy for Economic Development, and the GreenInfo Network. The atlas was used as a guide for evaluating the potential for renewable energy production from biomass, geothermal, solar, and wind resources. Estimates for annual energy production from each resource type by state are provided in the atlas. Staff used these estimates when adding generic renewable resources to the basecase, considering existing transmission and proximity to load centers when making the additions.

Figures A-3 and A-4 below illustrate where generic renewable capacity, and the associated energy production from these units, was added by state or province.

Figure A-3: Installed Renewable Capacity by State & Province Year 2017

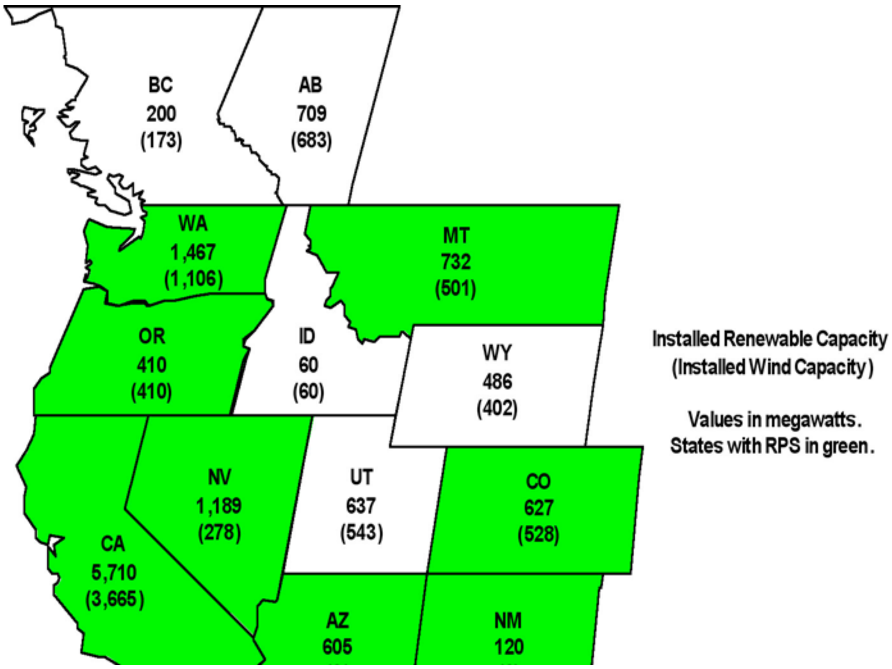
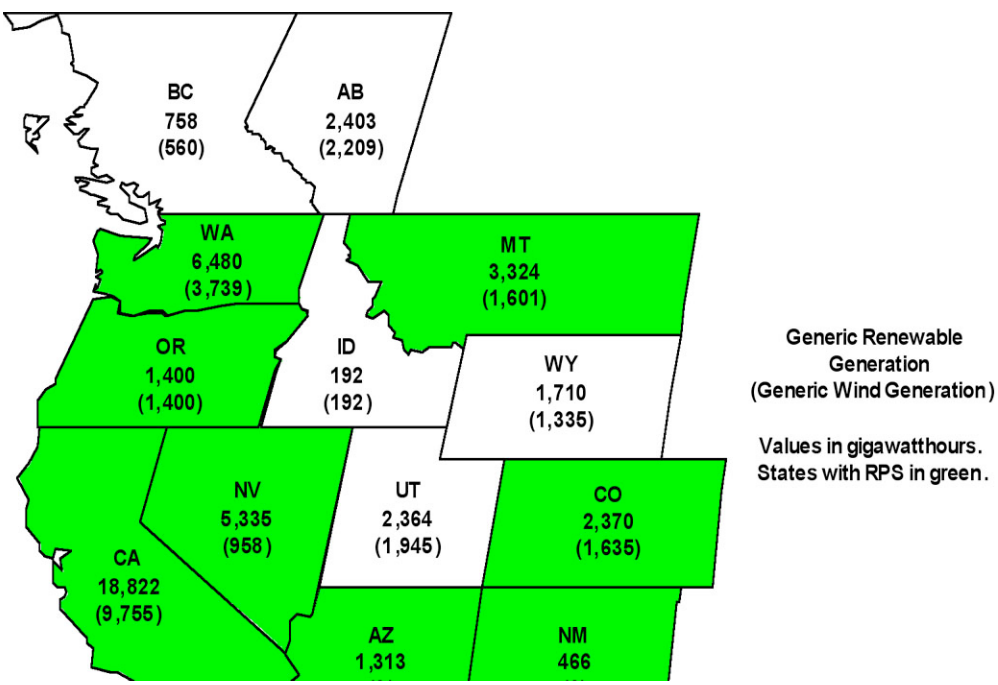


Figure A-4: Expected Generic Renewable Generation Year 2017 GWh



Generic Generation Additions

Subsequent to adding generic renewable resources to the basecase, staff reviewed data for peak demand and available dependable capacity at the control area level. Using a 15 percent reserve margin as a target, staff added generic thermal resources to the basecase in each area where needed.

The generic resource characterizations added to the basecase were developed by GED for use in the Marketsym model. The four types of generic thermal plants used were; a 500 MW pulverized coal plant, a 490 MW natural gas combined cycle plant, a 100 MW aero derivative gas turbine, and a 180 MW gas turbine. Table A-4 below provides an overview for each plant type.

Table A-4: Generic Thermal Power Plant Specifications

Generator Type					
Unit Characteristics	Units	Aero derivative Gas Turbine	Gas Turbine	Combined Cycle	Pulverized Coal
Date of Initial Entry	Year	2008	2008	2017	2011
Summer Capacity	MW	90	160	450	500
Winter Capacity	MW	100	180	490	500
Full Load Heat Rate	HHV, Btu/kWh	8,668	10,500	6,500	9,300
Forced Outage Rate	%	3.60%	3.60%	5.50%	6.00%
Maintenance Outage Rate	%	4.10%	4.10%	4.10%	6.50%

Arizona and California were given the most generic thermal capacity, nearly all of it being fueled by natural gas. Other areas receiving significant generic additions were Alberta, British Columbia, and Utah. For a complete list of the generic resource additions, please see Table A-5 at the end of this appendix.

Generation Retirements

For the purpose of this study, staff used retirement dates for generating units as determined by GED, with few exceptions. GED uses different assumptions for generation retirements based on the type and size of the unit in question. In general, renewable resources are not retired. When a renewable resource is known to have specific retirement date, GED assumes that it will be replaced by a similar type and size facility. For nuclear power plants, life expectancy is assumed to last through the end of the plants operating permit issued by the NRC, usually 40 years for the original license and 20 years for subsequent extensions. Large coal plants (>300 MW) are assumed to have a life expectancy of 75 years, while smaller coal plants are given a 55 year operational lifespan.

The 55 year lifespan for coal units of 300 MW or less is used for all other thermal plants, also. This is based on a “high level” survey conducted by GED that found very few of these types of units operate, or planned to operate, longer than 55 years. Table A-6 below provides the assumed annual retirements, by fuel type, for the forecast period.

Table A-6: Assumed Annual Capacity Retirements (MW)

Year	Coal	Fuel Oil	NG	Annual Total
2007		231	511	742
2008		75	338	413
2009		180	742	922
2010	293		190	483
2011			279	279
2012			554	554
2013	10		990	1,000
2014	19		770	790
2015			858	858
2016	48	10	896	954
2017	10	32	1,149	1,191
Total by Fuel Type	381	528	7,276	8,185

Natural Gas Fuel Use for Electric Generation

Based on these supply, demand and transmission assumptions, Table A-7, below, provides EAO’s forecast of natural gas demand for electric generation for California and the entire WECC region. This forecast is based on an average water year, average temperature conditions and load forecast, and current trends in RPS and other power generation legislative mandates throughout the WECC.

Table A-7: Natural Gas Demand for Electric Generation (GBtu)

	California	Rest of WECC	Total WECC
2008	855,998	895,143	1,751,141
2009	880,718	909,405	1,790,124
2010	899,150	969,825	1,868,974
2011	884,229	903,426	1,787,655
2012	914,716	962,872	1,877,588
2013	900,512	990,137	1,890,650
2014	911,567	1,053,603	1,965,170
2015	936,829	1,105,592	2,042,421
2016	969,060	1,139,012	2,108,072
2017	970,129	1,192,064	2,162,193

Figure A-1: 2008 WECC Topology

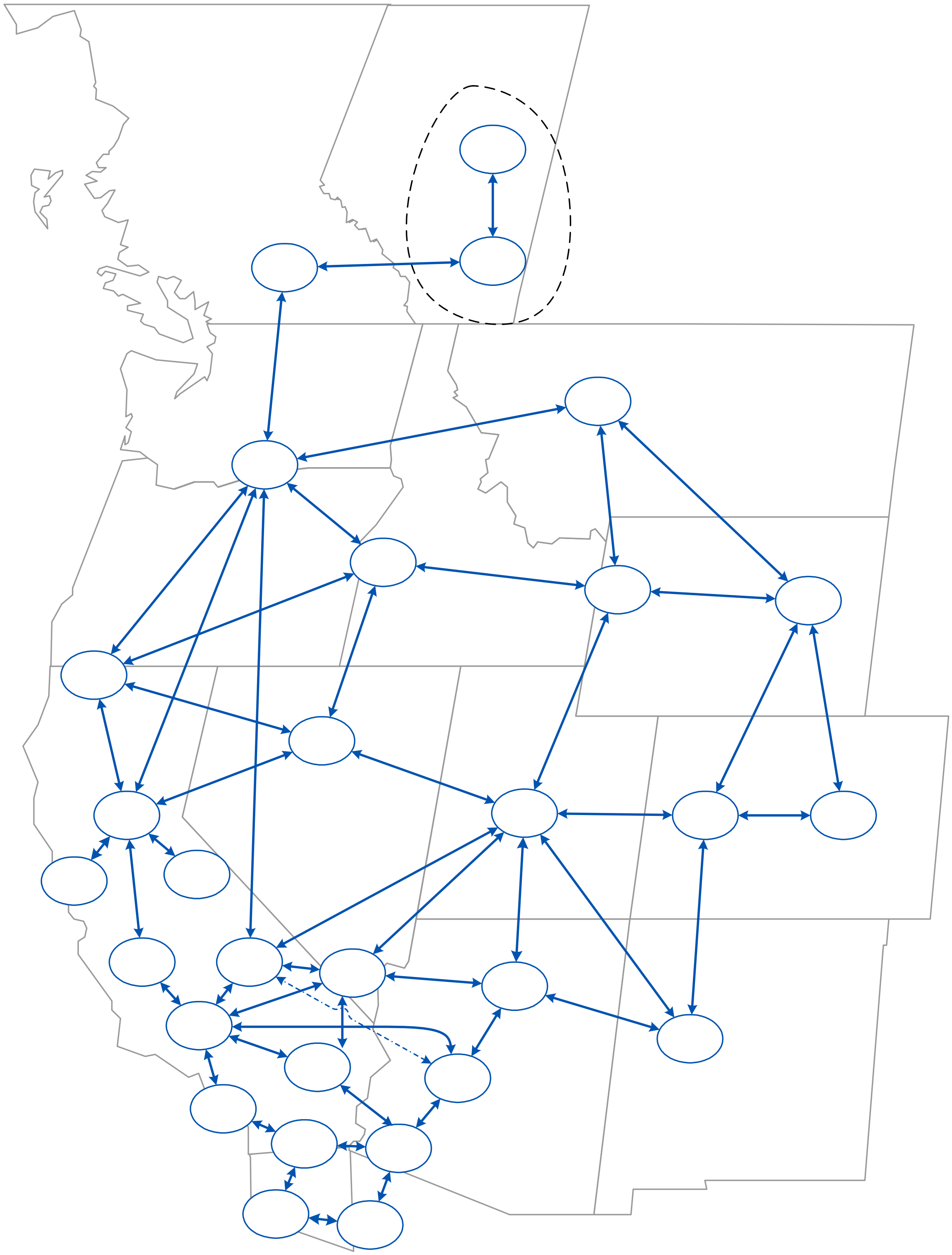


Figure A-2: 2017 WECC Topology

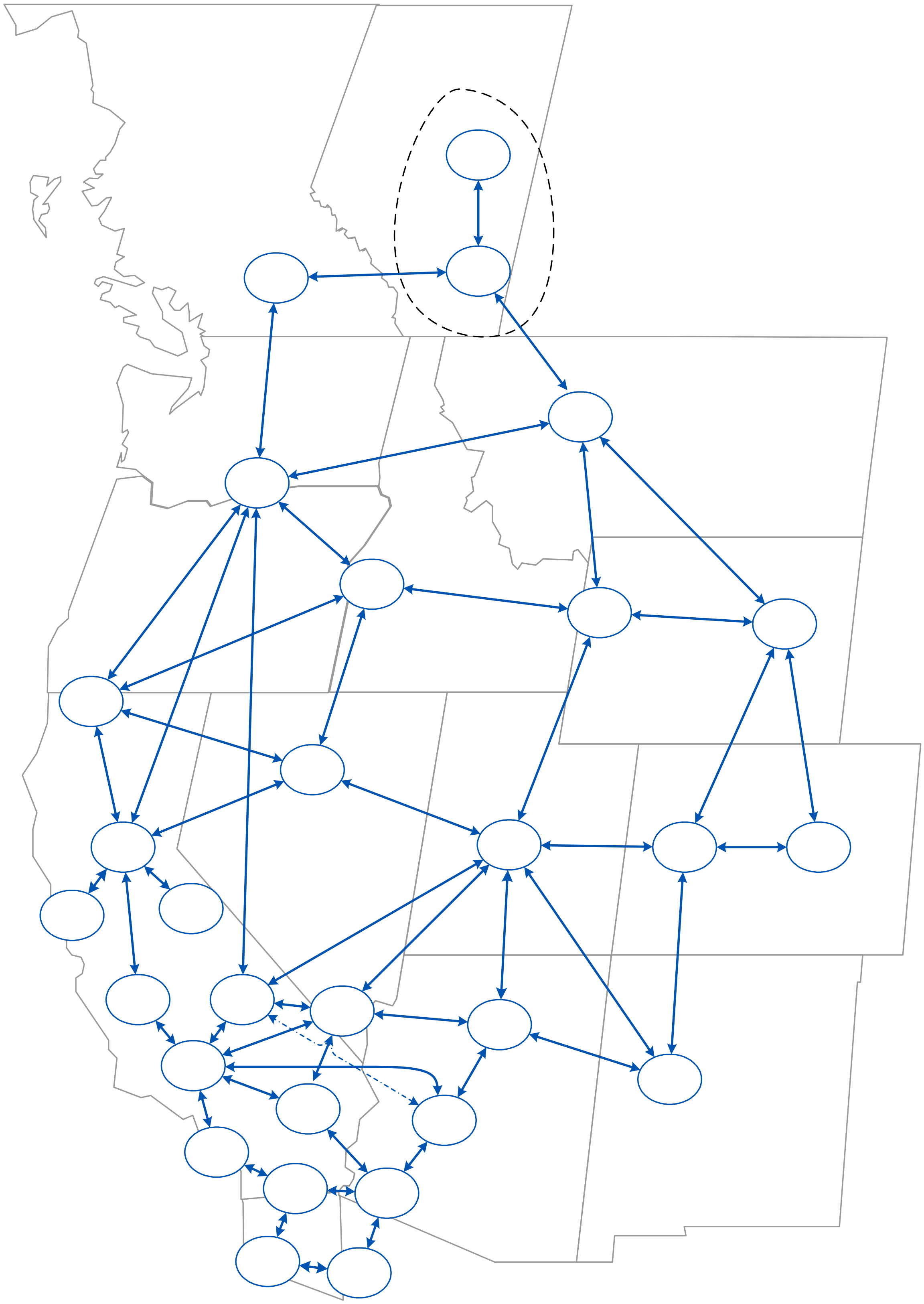


Table A-3: High Probability Named Additions

Unit Name	Unit No	Area	Unit Type	Capacity (MW)	Year	Fuel Type
Enmax Taber Wind Pro		AB	WT	80	2007	Wind
OPTI/Nexen Long Lake	1	AB	CGGT	85	2007	NG
OPTI/Nexen Long Lake	2	AB	CGGT	85	2007	NG
Steel Park Wind	15	AZ	WT	15	2007	Wind
_150 Mile House ERG	ST	BC	ST	5.9	2007	Other
Bone Creek		BC	HY	20	2007	Hydro
Clemina Creek		BC	HY	10	2007	Hydro
Mount Hays Wind Farm	14	BC	WT	25.2	2007	Wind
Savona ERG Project	ST	BC	ST	5.9	2007	Other
GenGTA_CSCE07 LB	1	CA	GenGT	100	2007	NG
GenGTA_CSCE07 LB	2	CA	GenGT	100	2007	NG
GenGTA_CSCE07 LB	3	CA	GenGT	50	2007	NG
Pine Tree Wind		CA	WT	120	2007	Wind
Roseville Energy	1a	CA	CC	87.5	2007	NG
Roseville Energy	1b	CA	CC	87.5	2007	NG
Windstar I	60	CA	WT	120	2007	Wind
Cedar Creek Wind Ene	200	CO	WT	300	2007	Wind
Peetz Wind (FPL)	133	CO	WT	199.5	2007	Wind
Spindle Hill	GT1	CO	GT	157	2007	NG
Spindle Hill	GT2	CO	GT	157	2007	NG
Twin Buttes Wind Far	50	CO	WT	75	2007	Wind
Burley Butte Wind Pa	17	ID	WT	10.5	2007	Wind
Lava Beds Wind		ID	WT	18	2007	Wind
Milner Dam Wind		ID	WT	18	2007	Wind
Notch Butte Wind		ID	WT	18	2007	Wind
Oregon Trail Wind Pa		ID	WT	10.5	2007	Wind
Pilgrim Stage Statio		ID	WT	10.5	2007	Wind
Raft River Geotherma		ID	GE	10	2007	Geothermal
Salmon Falls Wind		ID	WT	21	2007	Wind
Schwendiman Wind	18	ID	WT	20	2007	Wind
Thousand Springs Win	1-7	ID	WT	10.5	2007	Wind
Tuana Gulch Wind Par		ID	WT	10.5	2007	Wind
Afton CC	1	NM	CC	272	2007	NG
Nevada Solar One		NV	SS	64	2007	Solar
Salt Wells Geotherma	GE1	NV	GE	11	2007	Geothermal
Stillwater II	GE1	NV	GE	26	2007	Geothermal
Biglow Canyon	63	OR	WT	450	2007	Wind
Elkhorn Wind Power P	70	OR	WT	66	2007	Wind
Port Westward	1	OR	CC	400	2007	NG
Desert Power CC	1	UT	CC	45	2007	NG
Desert Power CC	2	UT	CC	45	2007	NG

Lake Side	1a	UT	CC	267	2007	NG
Lake Side	1b	UT	CC	267	2007	NG
White Creek Wind Pro	87	WA	WT	200	2007	Wind
Snowflake White Moun	ST	AZ	ST	20	2008	Biomass
Yuma Peaker	GT2	AZ	GT	50	2008	NG
Yuma Peaker	GT1	AZ	GT	50	2008	NG
Anyox River Hydroele		BC	HY	30	2008	Hydro
Bear Mountain Wind	60	BC	WT	120	2008	Wind
Dokie Wind Energy Pr	100	BC	WT	180	2008	Wind
East Toba River		BC	HY	120	2008	Hydro
Forrest Kerr		BC	HY	112	2008	Hydro
Glacier Creek		BC	HY	40	2008	Hydro
Gold River Power Pro	ST2	BC	ST	40	2008	Other
Gold River Power Pro	ST1	BC	ST	35	2008	Other
Howser Creek		BC	HY	49.6	2008	Hydro
Kitsault River Hydro		BC	HY	26.5	2008	Hydro
Kookipi Creek		BC	HY	10	2008	Hydro
Kwoiek Creek		BC	HY	50	2008	Hydro
Log Creek		BC	HY	10	2008	Hydro
Montrose Creek		BC	HY	50	2008	Hydro
Princeton Power Proj	ST1	BC	ST	49	2008	Coal
Rainy River Hydro		BC	HY	15	2008	Hydro
Humboldt Bay	C6	CA	IC	16.3	2008	NG
Humboldt Bay	C2	CA	IC	16.3	2008	NG
Humboldt Bay	C3	CA	IC	16.3	2008	NG
Humboldt Bay	C1	CA	IC	16.3	2008	NG
Humboldt Bay	C10	CA	IC	16.3	2008	NG
Humboldt Bay	C4	CA	IC	16.3	2008	NG
Humboldt Bay	C7	CA	IC	16.3	2008	NG
Humboldt Bay	C8	CA	IC	16.3	2008	NG
Humboldt Bay	C9	CA	IC	16.3	2008	NG
Humboldt Bay	C5	CA	IC	16.3	2008	NG
Inland Empire Energy	1	CA	CS	405	2008	NG
Inland Empire Energy	2	CA	CS	405	2008	NG
Niland	GT1	CA	GT	46.5	2008	NG
Niland	GT2	CA	GT	46.5	2008	NG
Olivenhain Hodges Pumped Storage	1	CA	PS	40	2008	Pump Storage
Pacific Wind	WT	CA	WT	205.5	2008	Wind
Panoche Energy Cente	GT2	CA	GT	100	2008	NG
Panoche Energy Cente	GT1	CA	GT	100	2008	NG
Panoche Energy Cente	GT3	CA	GT	100	2008	NG
Panoche Energy Cente	GT4	CA	GT	100	2008	NG
Salton Sea #6		CA	GE	215	2008	Geothermal
SFERP Potrero 1		CA	GT	49	2008	NG

SFERP Potrero 2		CA	GT	49	2008	NG
SFERP Potrero 3		CA	GT	49	2008	NG
Lamar Plant	AB	CO	AB	18	2008	Coal
Mountain Home	3	ID	GT	170	2008	NG
Raft River Geotherma	E2	ID	GE	26	2008	Geothermal
Hobbs	1a	NM	CC	288	2008	NG
Hobbs	1b	NM	CC	288	2008	NG
Reeves	CC	NM	CC	206	2008	NG
Ely Wind	1	NV	WT	200	2008	Wind
Galena 2		NV	GE	10	2008	Geothermal
Galena 3	GE	NV	GE	25	2008	Geothermal
Tracy (NV)	1a	NV	CCDF	249.5	2008	NG
Tracy (NV)	1b	NV	CCDF	249.5	2008	NG
TS Power Plant	1	NV	ST	200	2008	Coal
Sumas Recovered Ener	ST	WA	ST	5	2008	Other
Wygen II	1	WY	ST	90	2008	Coal
Springerville	4	AZ	ST	400	2009	Coal
Mackenzie Green Ener	ST	BC	CGST	50	2009	Biomass
Contra Costa Power	8a	CA	CCDF	235	2009	NG
Contra Costa Power	8b	CA	CCDF	235	2009	NG
Eastshore Energy Fac	IC	CA	IC	116	2009	NG
EIF Bullard	GT	CA	GT	196	2009	NG
El Centro CC	3	CA	CC	120	2009	NG
Otay Mesa	1a	CA	CCDF	255	2009	NG
Otay Mesa	1b	CA	CCDF	255	2009	NG
Starwood Power Fireb	GT	CA	GT	120	2009	NG
Comanche (CO)	3	CO	ST	750	2009	Coal
Torrance County Biom	ST1	NM	ST	35	2009	Biomass
Blue Mountain Geothe	GE	NV	GE	30	2009	Geothermal
Buffalo Valley	ST	NV	GE	30	2009	Geothermal
Carson Lake	ST	NV	GE	30	2009	Geothermal
Newberry Volcano	GE1	OR	GE	30	2009	Geothermal
Songhees Creek Hydro		BC	HY	15	2010	Hydro
Upper Stave Creek		BC	HY	33.6	2010	Hydro
Wapiti Energy	ST1	BC	ST	184	2010	Coal
PG&E Colusa County	1A	CA	CC	330	2010	NG
PG&E Colusa County	1B	CA	CC	330	2010	NG
Russell City	CC	CA	CC	620	2010	NG
Keephills	3	AB	ST	450	2011	Coal

Source: GED and California Energy Commission

Table A-5: Generic Thermal Resource Additions

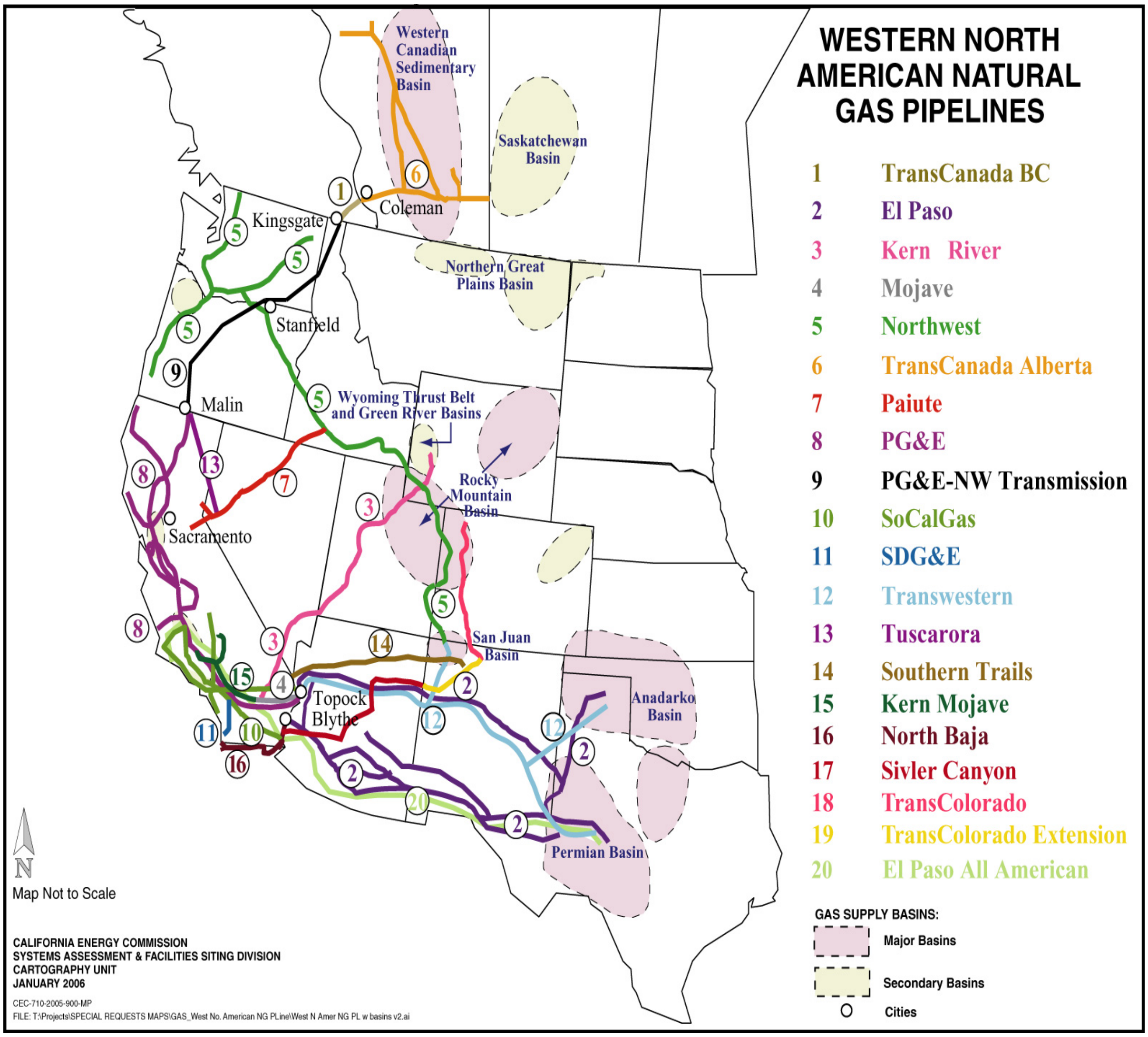
Unit Name	Unit No	Unit Type	Max Rating	Year	Fuel Type	Area
GenGT_AB_S08	4	GenGT	180	2008	NG	AB
GenGTA_CSCE08 Pkrs	1	GenGT	100	2008	NG	CA
GenGTA_CSCE08 Pkrs	2	GenGT	100	2008	NG	CA
GenGTA_CSCE08 Pkrs	3	GenGT	50	2008	NG	CA
GenGT_NBAJ09	1	GenGT	180	2009	NG	BCN
GenGT_NBAJ09	2	GenGT	180	2009	NG	BCN
GenGT__Ariz10	1	GenGT	180	2010	NG	AZ
GenGT__Ariz10	2	GenGT	180	2010	NG	AZ
GenGT__Ariz10	3	GenGT	180	2010	NG	AZ
GenGT_AB_S10	1	GenGT	180	2010	NG	AB
GenGT_AB_S10	2	GenGT	180	2010	NG	AB
GenGT_ABCN10	1	GenGT	180	2010	NG	AB
GenGT_ABCN10	2	GenGT	180	2010	NG	AB
GenGT__Ariz11	1	GenGT	180	2011	NG	AZ
GenGT__Ariz11	2	GenGT	180	2011	NG	AZ
GenGT__Ariz11	3	GenGT	180	2011	NG	AZ
GenGT__Ariz11	4	GenGT	180	2011	NG	AZ
GenGT_ABCN11	1	GenGT	180	2011	NG	AB
GenGT_BC11	1	GenGT	180	2011	NG	BC
GenGT_BC11	2	GenGT	180	2011	NG	BC
GenGT_BC11	3	GenGT	180	2011	NG	BC
GenGT_NBAJ11	1	GenGT	180	2011	NG	BCN
GenST_AB_S11	1	GenCoal	500	2011	Coal	AB
GenST_AZ11	1	GenCoal	500	2011	Coal	AZ
GenST_SNEV11	1	GenCoal	500	2011	Coal	NV
GenST_WYCE11	1	GenCoal	300	2011	Coal	WY
GenGT__Ariz12	1	GenGT	180	2012	NG	AZ
GenGT_CO E12	1	GenGT	180	2012	NG	CO
GenGT_NewM12	1	GenGT	180	2012	NG	NM
GenGT_PV23	1	GenGT	180	2012	NG	AZ
GenGT_PV23	2	GenGT	180	2012	NG	AZ
GenGT_PV23	3	GenGT	180	2013	NG	AZ
GenGT_PV23	4	GenGT	180	2013	NG	AZ
GenGT_PV28	1	GenGT	180	2013	NG	AZ
GenGT__Ariz14	1	GenGT	180	2014	NG	AZ
GenGT__Ariz14	2	GenGT	180	2014	NG	AZ
GenGT__Ariz14	3	GenGT	180	2014	NG	AZ
GenGT_AB_S14	1	GenGT	180	2014	NG	AB

GenGT_Ariz14	1	GenGT	180	2014	NG	AZ
GenGT_Ariz14	2	GenGT	180	2014	NG	AZ
GenGT_Ariz14	3	GenGT	180	2014	NG	AZ
GenGT_Ariz14	4	GenGT	180	2014	NG	AZ
GenGT_CO E14	1	GenGT	180	2014	NG	CO
GenGT_CO E14	2	GenGT	180	2014	NG	CO
GenGT_ID_S14	1	GenGT	180	2014	NG	ID
GenGT_Utah14	1	GenGT	180	2014	NG	UT
GenGT_Utah14	2	GenGT	180	2014	NG	UT
GenGT_Utah14	3	GenGT	180	2014	NG	UT
GenGTA_CSDG14	1	GenGT	100	2014	NG	CA
GenGTA_CSDG14	2	GenGT	100	2014	NG	CA
GenGTA_LADW14	1	GenGT	100	2014	NG	CA
GenGTA_LADW14	2	GenGT	100	2014	NG	CA
GenGTA_LADW14	3	GenGT	100	2014	NG	CA
GenGTA_LADW14	4	GenGT	100	2014	NG	CA
GenGTA_LADW14	5	GenGT	100	2014	NG	CA
GenGTA_LADW14	6	GenGT	100	2014	NG	CA
GenGTA_LADW14	7	GenGT	100	2014	NG	CA
GenGTA_LADW14	8	GenGT	100	2014	NG	CA
GenGT__Ariz15	1	GenGT	180	2015	NG	AZ
GenGT__Ariz15	2	GenGT	180	2015	NG	AZ
GenGT_CO E15	1	GenGT	180	2015	NG	CO
GenGT_CO E15	2	GenGT	180	2015	NG	CO
GenGT_NBAJ15	1	GenGT	180	2015	NG	BCN
GenGT_NBAJ15	2	GenGT	180	2015	NG	BCN
GenGT_NewM15	1	GenGT	180	2015	NG	NM
GenGT_Nort15	1	GenGT	180	2015	NG	WA
GenGT_Nort15	2	GenGT	180	2015	NG	WA
GenGT_Utah15	1	GenGT	180	2015	NG	UT
GenGT_Utah15	2	GenGT	180	2015	NG	UT
GenGT_Utah15	3	GenGT	180	2015	NG	UT
GenGT_Utah15	4	GenGT	180	2015	NG	UT
GenGTA_CNP115	1	GenGT	100	2015	NG	CA
GenGTA_CNP115	2	GenGT	100	2015	NG	CA
GenGTA_CSDG15	1	GenGT	100	2015	NG	CA
GenGTA_CSDG15	2	GenGT	100	2015	NG	CA
GenGTA_CSDG15	3	GenGT	100	2015	NG	CA
GenGTA_CSDG15	4	GenGT	100	2015	NG	CA
GenGTA_CSDG15	5	GenGT	100	2015	NG	CA
GenGTA_CSDG15	6	GenGT	100	2015	NG	CA
GenGTA_CSDG15	7	GenGT	100	2015	NG	CA
GenGTA_CSDG15	8	GenGT	100	2015	NG	CA
GenGTA_CSDG15	9	GenGT	100	2015	NG	CA
GenGTA_IID15	1	GenGT	100	2015	NG	CA

GenGTA_IID15	2	GenGT	100	2015	NG	CA
GenGTA_LADW15	1	GenGT	100	2015	NG	CA
GenGTA_LADW15	2	GenGT	100	2015	NG	CA
GenST_UT15	1	GenCoal	500	2015	Coal	UT
GenGT__Ariz16	1	GenGT	180	2016	NG	AZ
GenGT__Ariz16	2	GenGT	180	2016	NG	AZ
GenGT__Ariz16	3	GenGT	180	2016	NG	AZ
GenGT_AB_S16	1	GenGT	180	2016	NG	AB
GenGT_AB_S16	2	GenGT	180	2016	NG	AB
GenGT_Ariz16	1	GenGT	180	2016	NG	AZ
GenGT_Ariz16	2	GenGT	180	2016	NG	AZ
GenGT_Ariz16	3	GenGT	180	2016	NG	AZ
GenGT_ID_S16	1	GenGT	180	2016	NG	ID
GenGT_IDE_S16	1	GenGT	180	2016	NG	ID
GenGT_NBAJ16	1	GenGT	180	2016	NG	BCN
GenGT_Utah16	1	GenGT	180	2016	NG	UT
GenGTA_CSCE16	1	GenGT	100	2016	NG	CA
GenGTA_CSDG16	1	GenGT	100	2016	NG	CA
GenGTA_CSDG16	2	GenGT	100	2016	NG	CA
GenGTA_CSDG16	3	GenGT	100	2016	NG	CA
GenGTA_CSDG16	4	GenGT	100	2016	NG	CA
GenGTA_CSDG16	5	GenGT	100	2016	NG	CA
GenGTA_IID16	1	GenGT	100	2016	NG	CA
GenGTA_IID16	2	GenGT	100	2016	NG	CA
GenGTA_LADW16	1	GenGT	100	2016	NG	CA
GenGTA_LADW16	2	GenGT	100	2016	NG	CA
GenST_AZ16	1	GenCoal	500	2016	Coal	AZ
GenCCY_AB_S17	1	GenCC	245	2017	NG	AB
GenGT__Ariz17	1	GenGT	180	2017	NG	AZ
GenGT__Ariz17	2	GenGT	180	2017	NG	AZ
GenGT__Ariz17	3	GenGT	180	2017	NG	AZ
GenGT__Ariz17	4	GenGT	180	2017	NG	AZ
GenGT_ID_S17	1	GenGT	180	2017	NG	ID
GenGT_MT17	1	GenGT	180	2017	NG	MT
GenGT_NBAJ17	1	GenGT	180	2017	NG	BCN
GenGT_SNev17	1	GenGT	180	2017	NG	NV
GenGT_SNev17	2	GenGT	180	2017	NG	NV
GenGT_SNev17	3	GenGT	180	2017	NG	NV
GenGTA_CNP117	1	GenGT	100	2017	NG	CA
GenGTA_CNP117	2	GenGT	100	2017	NG	CA
GenGTA_CSDG17	1	GenGT	100	2017	NG	CA
GenGTA_CSDG17	2	GenGT	100	2017	NG	CA
GenGTA_CSDG17	3	GenGT	100	2017	NG	CA
GenGTA_CSDG17	4	GenGT	100	2017	NG	CA
GenST_COE17	1	GenCoal	500	2017	Coal	CO

APPENDIX B: PIPELINES SERVING CALIFORNIA

Figure B-1: Pipelines Serving California



APPENDIX C: HISTORICAL PRICE FORECASTS

Figure C-1: Historical Price Forecasts